EXHIBIT I

JENNER & BLOCK LLP
MATTHEW PRICE (*pro hac vice*)
1099 New York Avenue NW Suite 900
Washington, DC 20001
Telephone: (202) 639-6873
Facsimile: (202) 661-4802
mprice@jenner.com

THOMAS MELONE (*pro hac vice*)
MICHAEL MELONE (*pro hac vice)*
ALLCO RENEWABLE ENERGY LIMITED
14 Wall St., 20th Floor
New York, NY 10005
Telephone: (212) 681-1120
Facsimile: (801) 858-8818
Thomas.Melone@AllcoUS.com
MJMelone@AllcoUS.com

Attorneys for Plaintiff

FUTTERMAN DUPREE DODD CROLEY MAIER LLP
JAMIE L. DUPREE (158105)
JAIME G. TOUCHSTONE (233187)
180 Sansome Street, 17th Floor
San Francisco, CA 94104
Telephone: (415) 399-3906
Facsimile: (415) 399-3838
jdupree@fddcm.com
jtouchstone@fddcm.com

Local Attorneys for Plaintiff

UNITED STATES DISTRICT COURT

NORTHERN DISTRICT OF CALIFORNIA

SAN FRANCISCO DIVISION

WINDING CREEK SOLAR LLC, Plaintiff, v. MICHAEL PEEVEY, MICHAEL FLORIO, CATHERINE SANDOVAL, CARLA PETERMAN, and MICHAEL PICKER, in their official capacity as Commissioners of the California Public Utilities Commission, Defendants.	Case No. C 13-04934 JD **SECOND AMENDED COMPLAINT FOR DECLARATORY AND INJUNCTIVE RELIEF** **Honorable James Donato** **Leave to File Granted June 11, 2014**

NATURE OF THE ACTION

1. This case concerns the legality of a series of orders issued by the California Public Utilities Commission ("CPUC"). Those orders purport to implement federal regulations promulgated by the Federal Energy Regulatory Commission ("FERC") pursuant to the Public Utility Regulatory Policies Act ("PURPA"), Pub. L. 95-617 (Nov. 9, 1978).[1] Congress enacted PURPA to encourage the development of renewable energy generation and to reduce reliance on fossil fuels. It did so by imposing an obligation on electric utilities, like Pacific Gas & Electric, to purchase electricity at wholesale from certain renewable energy generators, called "qualifying facilities."

2. Congress called upon state regulatory commissions, like CPUC, to implement FERC's regulations for the electric utilities under their jurisdiction. Under FERC's regulations, an electric utility must purchase *any* electricity made available to it by a qualifying facility. An electric utility also must pay a particular price for those purchases: the utility's "avoided costs," that is, the amount the utility otherwise would have spent to buy or produce the electricity that it is required to purchase from the qualifying facility. Although the utility's avoided costs may be greater than the qualified facility's costs of production, Congress and FERC determined that allowing qualified facilities to receive the benefit of that difference would further the statutory purpose, by providing economic incentives to increase renewable energy production and improve efficiency. Consumers, meanwhile, would be left no worse off. Because their utility would pay no more than its avoided costs – that is, no more than the utility would otherwise pay to obtain that electricity – consumers' bills would not increase.

3. Federal regulations further provide that the utilities' avoided costs are to be calculated using two different methodologies. The first methodology determines the utility's avoided costs at the moment electricity is actually delivered to the utility – often calculated on a month-to-month basis, based on fluctuating market prices for natural gas or coal. The second

[1] Pursuant to the Court's May 21, 2014 Order, attached as an appendix to this Complaint is a table of acronyms used in this pleading, as well as key federal regulations and FERC decisions cited in this Complaint.

methodology determines the utility's projected avoided costs over the length of the entire contract with the qualified facility, calculated at the time the contract is entered. That second method provides a qualified facility with greater certainty concerning its revenues over the length of its contract with the utility. Federal regulations require that the qualifying facility be able to choose the pricing methodology it prefers.

4. As noted above, PURPA directs state regulatory commissions, like CPUC, to implement the federal regulations for each utility within its jurisdiction. While states have some flexibility in devising programs to implement the federal statute and regulations, they still must act within the boundaries of federal law. Thus, states may not exempt their utilities from the obligation to purchase renewable power under PURPA. Nor may states require their utilities to pay a price different than each utility's avoided costs, or refuse to offer renewable generators the ability to choose between the two pricing methodologies set forth in the federal regulations.

5. States have no authority to regulate the pricing of wholesale electricity contracts other than the authority provided to them by PURPA. With the exception of the specific authority afforded to states by PURPA, Congress has occupied the field of wholesale sales of electricity, and it has assigned to FERC exclusive authority to regulate that field. Accordingly, if a state regulatory commission were to require its utilities to pay a price different than the utility's avoided costs, such a requirement would be doubly preempted: it would not only conflict with PURPA, but would also fall within the field of wholesale electricity rate-setting, which, except for PURPA, Congress has reserved exclusively for FERC.

6. This case challenges a series of CPUC Orders – D.12-05-035 (the "May 2012 Order," attached as Exhibit A), D.13-01-041 (the "January 2013 Order," attached as Exhibit B), and D.13-05-034 (the "May 2013 Order," attached as Exhibit C) (collectively, the "Orders") – that purport to implement PURPA and the related federal regulations. These Orders require investor-owned electric utilities in the state, such as Pacific Gas & Electric, to enter into long-term (ten, fifteen, or twenty-year), fixed-price contracts with qualifying facilities. Rather than implementing PURPA and FERC's regulations, however, these Orders conflict with federal law in two main respects.

7. *First*, the Orders significantly limit the utilities' obligation to purchase electricity from qualifying facilities. They place an overall cap on the amount of electricity each utility is required to buy from qualifying facilities. For example, under the Orders, Pacific Gas & Electric is required to purchase only another 31 megawatts in total from qualifying facilities that generate electricity using solar technology. Moreover, during each two-month period, the Orders require each utility to enter into new contracts for only up to 5 megawatts of solar-generated electricity. Other qualifying facilities must wait in a queue. As a result, CPUC's program is oversubscribed. Today, Pacific Gas & Electric's queue contains 54 megawatts of solar-generated electricity – more than Pacific Gas & Electric will ever be required to purchase under CPUC's Orders. Federal law, which was enacted specifically to encourage the development of renewable energy generation, does not permit a state commission to limit utilities' purchase obligations in this manner.

8. *Second*, the Orders provide for a purchase price that is different than the utilities' avoided costs. CPUC's method for deciding which of the projects in the queue should receive a contract from the utility is to hold what is effectively a reverse auction, so that, over time, the price offered will be the lowest price at which qualifying facilities are willing to sell their electricity. That is inconsistent with federal law, which provides that the price of a contract entered into under PURPA must be based upon the *utility's* avoided costs, not the *qualifying facility's* production costs. Indeed, CPUC's pricing method frustrates the very purpose of PURPA, which was to promote renewable energy generation by mandating its purchase, so long as it was more cost-effective than the traditional, fossil-fuel based generation that it would displace. Yet CPUC's Orders, by forcing qualifying facilities to compete against one another to offer the lowest price, has the result of denying contracts to qualifying facilities that, even if more expensive than certain other qualifying facilities, are still more cost-effective than the highest-priced fossil-fuel based generation.

9. CPUC's sole authority to regulate wholesale electricity sales derives from PURPA. Therefore, any orders it issues must be consistent with PURPA and FERC's regulations implementing PURPA. Because CPUC's Orders are, in these two main respects, in

conflict with governing federal regulations concerning PURPA, the Orders are preempted and must be declared invalid. Additionally, CPUC should be enjoined from applying its Orders in the future, and should be ordered to issue new regulations that faithfully implement federal law.

PARTIES

10. Plaintiff Winding Creek Solar LLC ("Plaintiff") is the owner and developer of a 1.0 megawatt solar project located at 17016 North Jack Tone Road in Lodi, California ("the Lodi facility"). Allco Finance Limited is the sole member of Plaintiff.

11. Defendant Michael Peevey is President of the California Public Utilities Commission, and is sued in his official capacity.

12. Defendant Michael Florio is Commissioner of the California Public Utilities Commission, and is sued in his official capacity.

13. Defendant Catherine Sandoval is Commissioner of the California Public Utilities Commission, and is sued in her official capacity.

14. Defendant Carla Peterman is Commissioner of the California Public Utilities Commission, and is sued in her official capacity.

15. Defendant Michael Picker is Commissioner of the California Public Utilities Commission, and is sued in his official capacity.

JURISDICTION AND VENUE

16. This Court has subject matter jurisdiction over this action pursuant to 28 U.S.C. § 1331 because the action brings claims arising under federal law.

17. This Court also has subject matter jurisdiction over this action because, under 16 U.S.C. § 824a-3(h)(2)(B), a "qualifying small power producer," after first petitioning FERC, may bring an enforcement action in a United States district court against a State regulatory authority to enjoin violations of, and ensure compliance with, PURPA and FERC's regulations promulgated pursuant to PURPA.

18. A "qualifying small power producer" is statutorily defined as "the owner or operator of a qualifying small power production facility." 16 U.S.C. § 796(17)(D).

19. Plaintiff is a "qualifying small power producer" because it is the "owner" of the Lodi facility, which is a "qualifying small power production facility."

20. PURPA defines a "qualifying small power production facility" as "a small power production facility that the Commission [*i.e.*, FERC] determines, by rule, meets such requirements . . . as the Commission may, by rule, prescribe." 16 U.S.C. § 796(17)(C). PURPA defines the type of facility that is a "small power production facility": it "(i) produces electric energy solely by the use … of … renewable resources" and "(ii) has a power production capacity … not greater than 80 megawatts." 16 U.S.C. § 796(17)(A).

21. FERC has adopted regulations setting forth a definition of "qualifying small power production facility." These regulations provide that "a small power production facility is a qualifying facility if it: (1) Meets the maximum size criteria …; (2) Meets the fuel use criteria …; and (3) … has filed with the Commission a notice of self-certification, pursuant to § 292.207(a); or has filed with the Commission an application for Commission certification, pursuant to § 292.207(b)(1), that has been granted." 18 C.F.R. § 292.203(a).

22. The self-certification process referred to in Section 292.203(a) is set forth in 18 C.F.R. § 292.207(a). FERC has provided that "[t]he qualifying facility status of an existing or a proposed facility that meets the requirements of § 292.203 may be self-certified by the owner or operator of the facility" by submitting a particular form. 18 C.F.R. § 292.207(a).

23. The Lodi facility is a "qualifying small power production facility" pursuant to 18 C.F.R. § 292.203(a) because (1) it meets the maximum size criteria (it is a 1 megawatt facility, less than the 80 megawatt maximum); (2) it meets the fuel use criteria (it is designed to generate electric energy solely by the use of solar photovoltaic cells, which is a form of renewable energy); and (3) its owner, Plaintiff, on May 1, 2013, filed with FERC a notice of self-certification, pursuant to § 292.207(a), stating that the Lodi facility meets the requirements of § 292.203. *See* FERC Docket No. QF13-403-000.

24. Plaintiff, as the owner of the Lodi facility, has also satisfied the administrative exhaustion requirements of 16 U.S.C. § 824a-3(h)(2)(B). On June 13, 2013, Plaintiff petitioned FERC to bring an enforcement action against CPUC pursuant to Section 824a-3(h)(2)(A). On

August 12, 2013, FERC gave notice that it would not initiate an enforcement action under that section. *See Winding Creek Solar LLC*, 144 FERC ¶ 61,122 (2013).

25. The Court is empowered to grant declaratory relief by 28 U.S.C. §§ 2201 and 2202 and Rule 57 of the Federal Rules of Civil Procedure.

26. This Court is empowered to grant preliminary and permanent injunctive relief by, *inter alia*, 28 U.S.C § 2202; Rule 65 of the Federal Rules of Civil Procedure; and *Ex Parte Young*, 209 U.S. 123 (1908).

27. This Court has personal jurisdiction over Defendants because each Defendant conducts a substantial portion of his or her duties as an officer of CPUC in the Northern District of California. CPUC is located at 505 Van Ness Avenue, San Francisco, CA 94102.

28. Venue is proper in this District under 28 U.S.C. § 1391(b)(1) and (2) because a substantial part of the events giving rise to this action occurred in the Northern District of California.

29. INTRADISTRICT ASSIGNMENT: Assignment to the San Francisco division of this Court is proper because the Defendants are located in San Francisco and Defendants' acts and practices that form the basis for the violations alleged in this complaint occurred in San Francisco.

STATUTORY AND REGULATORY FRAMEWORK

30. Through the Federal Power Act, Congress occupied the field of wholesale electricity sales, and assigned to the Federal Power Commission – now FERC – exclusive authority to regulate that field. *See* 16 U.S.C. § 824(b)(1); *PPL EnergyPlus LLC v. Nazarian*, --- F.3d ----, 2014 WL 2445800, at *4-5 (4th Cir. June 2, 2014) (collecting "[a] wealth of case law confirm[ing] FERC's exclusive power to regulate wholesale sales of energy in interstate commerce").

31. In 1978, Congress enacted PURPA, which amended the Federal Power Act. Congress's purpose in enacting PURPA was to facilitate the development of renewable energy generation and to reduce the country's reliance on fossil fuels.

32. Prior to the enactment of PURPA, small renewable energy generators had difficulty finding buyers for their output, because electric utilities were reluctant to purchase power from non-traditional generation facilities. PURPA addressed that problem by directing FERC to adopt rules *requiring* electric utilities to purchase power generated by, among others, "qualifying small power production facilities." 16 U.S.C. § 824a-3(a). As noted above, this type of facility is small in size (less than 80 megawatts) and is designed to produce electricity solely through the use of a renewable fuel source. *See supra* at ¶¶ 20-21.

33. Pursuant to PURPA's directive, FERC provided in its regulations that "[e]ach electric utility shall purchase … any energy and capacity which is made available from a qualifying facility … [d]irectly to the electric utility." 18 C.F.R. § 292.303(a). A utility's obligation to purchase all the output of a qualifying facility that is interconnected with its distribution network is known as a "legally enforceable obligation." Once the utility's legally enforceable obligation is triggered, the utility becomes bound to purchase any electricity the qualifying facility produces. In California and elsewhere, state regulatory commissions have implemented PURPA by requiring the utility, in light of its legally enforceable obligation, to enter into a power purchase agreement with the qualifying facility, in which the utility commits to purchase the qualifying facility's electricity for a defined contract term.

34. PURPA also directed FERC to promulgate rules ensuring that "in requiring any electric utility to offer to purchase electric energy from any … qualifying small power production facility, the rates for such purchase" shall not "exceed[] the incremental cost to the electric utility of alternative electric energy." 16 U.S.C. § 824a-3(b).

35. Pursuant to that statutory directive, FERC promulgated a regulation providing that "a rate for purchases satisfies the requirements" of PURPA "if the rate equals the avoided costs" of the utility. 18 C.F.R. § 292.304(b)(2). The avoided costs of a utility, in turn, are to be determined after considering various factors set forth in Section 292.304(e), including specific data the utility must collect concerning its operational and cost characteristics. *Id.* § 292.302(b). The regulation further emphasizes that, while rates for purchases from existing facilities may be set lower than the utility's avoided cost in certain circumstances, *id.* §292.304(b)(3), "[r]ates for

purchases from new capacity" – that is, from facilities constructed after PURPA's enactment, *id.* § 292.304(b)(1) – "shall be in accordance with paragraph (b)(2) of this section," that is, equal to, and not less than, the utility's avoided costs. *Id.* § 292.304(b)(4); *see also Am. Paper Inst. v. Am. Electric Power Serv. Corp.*, 461 U.S. 402, 417 (1983) (upholding FERC's decision to require a rate equal to the full amount of the utility's avoided costs, and not less than that amount).

36. FERC's regulations also detail the methodologies that must be used in determining a utility's avoided costs, and provide that the qualifying facility has the option to choose which of two methodologies shall be used in calculating the utility's avoided costs. *Id.* § 292.304(d). When a qualifying facility provides "energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, … the rates for such purchases shall, *at the option of the qualifying facility* exercised prior to the beginning of the specified term, be based on either: (i) The avoided costs calculated at the time of delivery; or (ii) The avoided costs calculated at the time the obligation is incurred." *Id.* § 292.304(d)(2) (emphasis added).

37. The first methodology – "[t]he avoided costs calculated at the time of delivery," *id.* § 292.304(d)(2)(i) – is known in the industry as a "short run avoided cost" ("SRAC") rate, because it can be determined only at the moment that electricity is delivered. Typically, the "short run avoided cost" is calculated on a month-to-month basis, and depends in part upon the fluctuating market price of natural gas or coal. The second methodology – "[t]he avoided costs calculated at the time the obligation is incurred," *id.* § 292.304(d)(2)(ii) – is known in the industry as a "long run avoided cost" ("LRAC") rate, because it is determined at the time the utility incurs the purchase obligation, and is determined for the entire duration of the contract term. A utility's long-run avoided costs are typically calculated through the use of a mathematical model that projects the utility's anticipated avoided costs in the future, accounting for the many variables that might affect those avoided costs.

38. PURPA provides that each state's regulatory authority "implement [FERC]'s rule … for each electric utility for which it has ratemaking authority." 16 U.S.C. § 824a-3(f)(1). That provision constitutes a limited exception to FERC's exclusive regulatory authority over

wholesale electricity sales. Aside from "implement[ing]" FERC's rules under PURPA, *id.*, however, state regulatory commissions enjoy no authority to regulate wholesale electricity sales.

39. Section 824a-3(f)(1) affords state regulatory commissions some latitude in implementing FERC's rules under PURPA. For example, with respect to qualifying facilities still in development, state regulatory commissions have some flexibility to establish rules concerning the point at which projects are deemed sufficiently viable to trigger a utility's legally enforceable obligation. *See, e.g.*, *Power Resource Group, Inc. v. Pub. Utility Comm'n of Texas*, 422 F.3d 231 (5th Cir. 2005) (upholding Texas law limiting a utility's legally enforceable obligation to those qualifying facilities able to deliver electricity within 90 days). In its Orders purporting to implement PURPA, CPUC has decided that a utility's legally enforceable obligation is triggered so long as a qualifying facility in development can satisfy six "project viability criteria," which include a contractual commitment to be online and delivering electricity within 24 months of the contract date, with one 6-month extension for regulatory delays. May 2012 Order at 69-70. A qualifying facility that failed to meet that deadline would then be liable to the utility for breach of contract; contractual remedies under CPUC's program include the forfeiture of development security.

40. Section 824a-3(f)(1) also gives state regulatory commissions some latitude in calculating avoided costs and in setting the actual contract rate accordingly. However, state regulatory commissions are not permitted to adopt a rate for purchases based on some measure *other* than the utility's avoided costs. *See Independent Energy Producers Ass'n, Inc. v. Cal. Pub. Utilities Commission*, 36 F.3d 848, 857-58 (9th Cir. 1994). Nor, under the federal regulations, are state regulatory commissions permitted to offer qualifying facilities pricing under only one of the two methodologies prescribed by 18 C.F.R. § 292.304(d)(2) – *e.g.*, only a short-run avoided cost rate, and not a long-run avoided cost rate. The federal regulations are clear that the utility gets to choose whichever of those two pricing methodologies it wishes.

FACTUAL ALLEGATIONS

41. Prior to the issuance of the Orders under challenge here, qualifying facilities in California seeking to enter into contracts with utilities under PURPA had been able to choose

between two pricing methodologies reflecting two different ways of calculating a utility's avoided costs – just as federal regulations require. *See* 18 C.F.R. § 292.304(d)(2). The first, a short-run avoided cost price, was calculated month to month over the contract term, depending upon, among other things, the price of natural gas and the price of intrastate transportation of gas. These inputs could fluctuate over time. The second, a long-run avoided cost rate, was calculated "to reflect the long-term ownership, operating, and fixed-price fuel costs" for a new, 500 megawatt natural gas-fired power plant. May 2012 Order at 7. This rate was intended "to represent the long term market price of electricity for fixed price contracts." *See* CPUC Order D.11-04-033 at 23 (attached as Exhibit D). CPUC based its long-run avoided cost rate on the costs of a natural gas-fired plant because it assumed that, but for the obligation to buy electricity from qualifying facilities, the utilities most likely would have purchased electricity from, or generated electricity through the use of, a natural gas-fired generation facility. Accordingly, the costs that would be associated with a long-term, fixed-price contract with a natural gas-fired facility represented the long-run costs that the utility would avoid by contracting with qualifying facilities instead. *Id.* at 21-22.

42. On May 24, 2012, CPUC issued the May 2012 Order, in order to implement statutory amendments to Cal. Pub. Util. Code § 399.20 (known as the "Feed-In Tariff" program), purportedly pursuant to PURPA. *See* May 2012 Order at 10-13. These Orders replaced the long-run avoided cost rate that California had previously offered to qualifying facilities.

43. On their face, the statutory amendments to Cal. Pub. Util. Code § 399.20 appear consistent with PURPA's requirement that long-run pricing reflect a utility's avoided costs as calculated at the time the contractual obligation is incurred. For example, the amendments direct CPUC to adopt a long-run pricing methodology that reflects the "long-term market price of electricity for fixed price contracts, determined pursuant to an electrical corporation's general procurement activities as authorized by the commission." Cal. Pub. Util. Code § 399.20(d)(2)(A). Likewise, the amendments direct CPUC to adopt a long-run pricing methodology that reflects the "long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities." *Id.* § 399.20(d)(2)(B).

44. Nonetheless, as detailed below, CPUC's May 2012 Order adopted a long-run pricing methodology that does not reflect utilities' avoided costs, and therefore – even if authorized by state law – violates PURPA and applicable federal regulations.

45. Under the May 2012 Order – and as reaffirmed in the January 2013 Order and the May 2013 Order – qualifying facilities that seek a long-run avoided cost rate under PURPA must participate in a program called the "Renewable Market-Adjusting Tariff," also known as "Re-MAT" for short.

46. In order to implement the Re-MAT program, CPUC approved a tariff for each participating investor-owned utility – Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric. The Re-MAT tariff for Pacific Gas & Electric became effective on July 24, 2013, and Pacific Gas & Electric began awarding contracts under the program on November 1, 2013. The contracts are fixed-price contracts with a duration of ten, fifteen, or twenty years.

A. Eligibility to Participate in the Re-MAT Program.

47. In order to be eligible to participate in the Re-MAT program and be able to receive a contract from a utility, a facility must be a qualifying facility pursuant to PURPA. May 2012 Order at 11; May 2013 Order at 49 ([T]he program … is only available to sellers that are [qualifying facilities]… It is the responsibility of the sellers to complete all necessary documents with FERC. If FERC does not require any action be taken to be a [qualifying facility,] we will not require any."). In addition, the qualifying facility must satisfy six "project viability criteria" established by CPUC: (1) payment of a bid fee; (2) performance of a study concerning the impact that the facility's interconnection with the grid would have on the electrical system; (3) control of the site on which the qualifying facility will be built, or an option to lease or purchase that could be exercised once a contract with the utility is executed; (4) prior development experience; (5) an online date within 24 months of the contract date with one 6-month extension; and (6) a lack of market power. May 2012 Order at 69-70.

48. A project meeting these criteria is eligible to enter a "queue" to receive a contract from a utility. (Upon executing the contract, the qualifying facility will also need to post a

development security bond, which would compensate the utility in the event that the qualifying facility fails to meet its contractual online date.) A project's place in a queue is on a first-come, first-served basis.

49. Each utility maintains three separate "queues," one for each of three types of generation facilities. One queue is for "baseload" facilities – that is, facilities that can dependably generate electricity under all circumstances (for example, geothermal facilities, which generate electricity using heat from beneath the earth's crust). A second queue is for "non-peaking, as available" facilities, which are typically wind-powered facilities. The ability of such facilities to generate electricity may depend upon conditions, such as whether the wind is blowing – and thus they sell their electricity "as available." Further, such facilities do not necessarily generate electricity at times of peak demand – for example, a wind-powered facility may generate electricity during cool and breezy nights, when demand for electricity is low – and thus they are called "non-peaking" facilities. The third queue is for "peaking, as available" facilities, which are typically solar generation facilities. The ability of such facilities to generate electricity also depends upon conditions, such as whether the sun is shining, and therefore they sell their electricity "as available." But these facilities tend to generate electricity at times when demand is at its peak – for example, a hot, sunny summer afternoon – and therefore are called "peaking" facilities. As further explained below, the Re-MAT program is designed to provide a different price to each of these three types of generation facilities.

B. The Re-MAT Program Places Limits on the Amount of Electricity That Utilities Are Required to Purchase.

50. Under the statutory amendments to Cal. Pub. Util. Code § 399.20, the total size of the Re-MAT program is capped at 750 megawatts. In the May 2012 Order, CPUC directed that each of the three investor-owned utilities participating in the Re-MAT program were responsible for procuring a portion of the 750-megawatt total that accords with their share of statewide electricity demand. Under this metric, Pacific Gas & Electric is required to procure only 218.8 megawatts under the Re-MAT program. *See* May 2012 Order at 78.

51. The May 2012 Order further divides each investor-owned utility's share among the three subcategories of renewable generation technology. May 2012 Order at 42-44, 49. Thus, Pacific Gas & Electric is required to purchase one-third of its total cap – about 42.9 megawatts – from "baseload" generation facilities, one-third from "peaking, as-available," and one-third from "non-peaking, as available". *See* PG&E, ReMAT Feed-In Tariff, http://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/ReMAT/ (attached as Exhibit E).

52. Pacific Gas & Electric has already entered into a number of power purchase agreements. As a result, Pacific Gas & Electric's remaining obligation for "peaking, as available" facilities is currently only approximately 31.1 megawatts. *See* Exhibit E.

53. As a result of CPUC's decision to limit each utility's obligation to purchase electricity from qualified facilities, the Re-MAT program is oversubscribed. Pacific Gas & Electric's queue for "peaking, as available" facilities currently contains projects amounting to 54.1 megawatts – about 23 megawatts more than the CPUC Orders obligate Pacific Gas & Electric to buy. *See* Pacific Gas & Electric Company, ReMAT Queue Information, http://www.pge.com/includes/docs/pdfs/b2b/energysupply/wholesaleelectricsuppliersolicitation/ReMat/Program_Period_4_Queue_Information.pdf (attached as Exhibit F). As a practical matter this means that Pacific Gas & Electric will not purchase available solar-based energy from qualifying facilities, despite the fact that federal regulations require that utilities purchase "any energy and capacity which is made available from a qualifying facility … [d]irectly to the electric utility." 18 C.F.R. § 292.303(a).

54. To make matters worse, under the May 2013 Order, in each bi-monthly period, Pacific Gas & Electric may not enter into contracts for more than 5 megawatts for each of the three types generation facilities. May 2013 Order at 10-15, 20-21. Thus, for example, in any given two-month period, Pacific Gas & Electric may not enter contracts for more than 5 megawatts of electricity from "peaking, as available" facilities – despite the fact that the queue for such projects contains 54.1 megawatts, and, again, despite the federal requirement that utilities purchase all energy made available by qualifying utilities.

C. The Price Offered By the Re-MAT Program Is Not an Avoided Cost Price.

55. The 5 megawatt-cap described above is central to the Re-MAT program's mechanism for setting the price at which those contracts are awarded.

56. Every two months, each participating utility offers to enter a contract, at a particular price, with the qualifying facilities in a queue. (As noted above, each utility has three queues, one for each type of generation facility, and this process is carried out for each of the utility's queues.) The price offered by a utility under the Re-MAT program is fixed for the length of the contract term, which is either 10 years, 15 years, or 20 years.

57. An offer is made to each project in the queue, in order of the project's position in the queue, until the utility has reached the 5-megawatt cap for that two-month period. If a qualifying facility accepts the price offered, it enters into the contract with the utility. If a qualifying facility declines the price, it maintains its position in the queue until the next two-month period. If there are at least five projects in the queue, and none is willing to accept the price offered by the utility, then no contracts will be awarded, but the offer price will increase in the next two-month period based on a CPUC-determined formula. If the utility is able to enter contracts for the full 5 megawatts, then the offer price will decrease in the next two-month period based on a CPUC-determined formula. If the utility is able to contract for at least 1 megawatt, but does not reach its 5 megawatt cap, then the price will stay the same in the next two-month period. *See* May 2012 Order at 44-48; May 2013 Order at 13-14. Finally, if there are fewer than five separate projects from five unrelated developers in a queue, as has been the case in the "baseload" and "as-available, non-peaking" queues, then the price for that queue will stay the same in the next two-month period.

58. For example, in the initial two-month period (beginning November 1, 2013), Pacific Gas & Electric offered to purchase electricity from qualifying facilities in its "peaking, as-available" queue for a base price of $89.23/megawatt-hour. CPUC established this as the initial price based on the amount that the utilities paid for renewable energy at an auction

sponsored by CPUC in November 2011. *See* May 2012 Order at 42-44.[2] Pacific Gas & Electric entered into contracts with qualified facilities in its queue at that initial price for the full 5 megawatts available in that initial two-month period.

59. In the next two-month period (beginning January 1, 2014), Pacific Gas & Electric offered a base price of $85.23/megawatt-hour, a reduction in price dictated by the CPUC-determined formula. Pacific Gas & Electric again entered into contracts with qualified facilities in its queue for the full 5 megawatts available in that two-month period.

60. In the next two-month period (beginning March 1, 2014), Pacific Gas & Electric offered a further-reduced base price, this time to $77.23/megawatt-hour, again pursuant to the CPUC-determined formula. And, again Pacific Gas & Electric entered into contracts with qualifying facilities in its queue for the full 5 megawatts available in that two-month period.

61. In the current two-month period (which began on May 1, 2014), Pacific Gas & Electric offered a base price of $65.23/megawatt-hour. If Pacific Gas & Electric is able to enter contracts for 5 megawatts at that price, the base price for the next two-month period (beginning July 1, 2014) will drop even further, to $53.23/megawatt-hour. If Pacific Gas & Electric is not able to enter any contracts at $65.23/megawatt-hour, then the base price for the next two-month period will increase to $69.23/megawatt-hour. If Pacific Gas & Electric is able to contract for at least 1.0 megawatt but not 5 megawatts during this period, then the base price will stay the same for the next two-month period.

62. As a result of these decreasing prices, a project that entered into a contract in the initial two-month period of the Re-MAT program received a substantially higher price for its electricity than a project that entered into a contract in a subsequent period.

63. The prices offered by Pacific Gas & Electric, as mandated by the CPUC Orders, have no relationship at all to Pacific Gas & Electric's avoided costs – that is, they have no

[2] The auction involved renewable energy projects that were significantly larger than those eligible for the Re-MAT program – typically projects about 20 megawatts in size. Because larger projects typically must be located further away from populated areas than smaller projects, transmitting that electricity to consumers is typically more costly to utilities than transmitting electricity from smaller projects located closer to populated areas.

relationship whatsoever to the costs that Pacific Gas & Electric would otherwise incur if, instead of contracting with the qualifying facility, it had generated that electricity itself or procured it from another source.

64. Rather, the Re-MAT program's pricing mechanism is intended, over time, to identify the lowest price at which a qualifying facility is willing to sell electricity. In other words, the Re-MAT program's pricing is intended to reflect the qualifying facility's production costs – not the utility's avoided costs. This approach inverts the policy adopted by PURPA and implemented by FERC's regulations.

65. In its Orders, CPUC has made clear that the Re-MAT program is designed so that prices paid to qualifying facilities under the Re-MAT program reflect those facilities' production costs. The May 2012 Order, for example, explains that CPUC "seek[s] to pay generators [*i.e.*, qualifying facilities] the price needed to build and operate a renewable generation facility." May 2012 Order at 42;[3] *id.* at 33 (rejecting certain proposed adjustments to the price on the ground that "these adders could increase the contract price above the resource's actual costs and lead to overpayment"). The January 2013 Order confirms that "the rationale for a market-based price is that all of the generator's costs are included in the price because a generator would not bid something lower than its costs. In a market-based process, the seller determines the price it wishes to seek based on its understanding of the underlying project costs, and changes in those costs." January 2013 Order at 6.

INJURIES TO BE REDRESSED

66. The Lodi facility, owned by Plaintiff, is registered with FERC as a qualifying facility and satisfies the six project viability criteria set forth in the May 2012 Order. Thus, under the rules established by CPUC, the Lodi facility is eligible to receive a contract from a utility.

[3] CPUC's January 2013 Order subsequently deleted this statement lest it be misconstrued to suggest that the qualifying facilities participating in the Re-MAT program enjoyed some guarantee of cost recovery. *See* January 2013 Order at 6-7. Nevertheless, the pricing theory implied by this observation remains pertinent.

67. The Lodi facility is currently in Pacific Gas & Electric's "queue" for "peaking, as available" facilities. Indeed, the Lodi facility currently occupies the first position in that queue.

68. In the two-month period beginning March 1, 2014, Pacific Gas & Electric offered the Lodi facility a long-term contract at the CPUC-mandated base price of $77.23/megawatt-hour. Plaintiff, as the owner of the Lodi facility, declined to enter into a contract at that price.

69. In the two-month period beginning May 1, 2014, Pacific Gas & Electric offered the Lodi facility a long-term contract at the CPUC-mandated base price of $65.23/megawatt-hour. Again, Plaintiff, as the owner of the Lodi facility, declined to enter into a contract at that price.

70. In the two month period beginning July 1, 2014, Pacific Gas & Electric will again offer the Lodi facility a long-term contract at the CPUC-mandated base price for that period, as described in paragraph 61 above.

71. Plaintiff seeks to enter into a contract with Pacific Gas & Electric, pursuant to PURPA, on terms consistent with federal law concerning the pricing of such contracts.

72. On information and belief, Pacific Gas & Electric's long-run avoided costs are higher than the current Re-MAT price offered by Pacific Gas & Electric, pursuant to CPUC's Orders, for "peaking, as available" qualifying facilities.

73. Plaintiff, as owner of the Lodi facility, has suffered an injury-in-fact because the Re-MAT pricing mechanism adopted by CPUC is not based on Pacific Gas & Electric's avoided costs, and, on information and belief, has resulted in an offer price that is lower than Pacific Gas & Electric's long-run avoided costs. As a result, Plaintiff has been denied the opportunity to enter into a contract with Pacific Gas & Electric on terms required by federal law.

74. A favorable ruling in Plaintiff's favor, declaring the Re-MAT scheme to be preempted and requiring CPUC to implement PURPA in a manner consistent with federal regulations concerning pricing, would redress that injury-in-fact, by providing Plaintiff the opportunity to enter into a contract with Pacific Gas & Electric on terms required by federal law.

75. Plaintiff, as owner of the Lodi facility, has also suffered an injury-in-fact because the price currently offered under CPUC's Re-MAT pricing mechanism, $65.23/megawatt-hour,

which Plaintiff alleges is in conflict with federal law, is too low to enable Plaintiff to obtain the financing needed to construct the Lodi facility.

76. The low pricing under the Re-MAT program is the only remaining barrier to Plaintiff's ability to obtain the financing needed to construct the Lodi facility.

77. A favorable ruling in Plaintiff's favor, declaring the Re-MAT scheme to be preempted and requiring CPUC to implement PURPA in a manner consistent with federal regulations concerning pricing, is, on information and belief, substantially likely to result in a price high enough to allow Plaintiff to obtain the financing needed to construct the Lodi facility.

CLAIM FOR RELIEF

COUNT I: PREEMPTION
(Violation of the Supremacy Clause of the U.S. Constitution and 42 U.S.C. § 1983)

78. Plaintiffs restate and incorporate by reference each and every allegation in Paragraphs 1 through 77 as if fully set forth herein.

79. Under the Supremacy Clause of the United States Constitution, a state law is preempted when Congress intends federal law to occupy the field, as well as in cases where the state law conflicts with federal statutes or regulations, or where the state law stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress.

80. In passing the Federal Power Act, Congress intended FERC to have exclusive jurisdiction over the field of wholesale electricity sales. Section 201(b) of the Federal Power Act, codified at 16 U.S.C. § 824(b), sets out the scope of federal regulatory power and draws a bright line between mutually exclusive spheres of state and federal regulatory authority. The Federal Power Act left no power in states to regulate wholesale electricity pricing or sales.

81. In 1978, Congress enacted PURPA, codified at 16 U.S.C. § 824a-3, which amended the Federal Power Act and created a limited role for states in setting rates for certain wholesale transactions.

82. Other than the authority granted to the states in PURPA, states have no other authority to set wholesale electricity rates or regulate wholesale electricity transactions.

83. PURPA directed FERC to adopt rules requiring electric utilities to purchase power generated by, among others, "qualifying small power production facilities." 16 U.S.C. § 824a-3(a). PURPA then directed state regulatory commissions, like CPUC, to implement FERC's regulations.

84. Under FERC's regulations, "[e]ach electric utility shall purchase … any energy and capacity which is made available from a qualifying facility … [d]irectly to the electric utility." 18 C.F.R. § 292.303(a).

85. CPUC's Re-MAT program, as set forth in the Orders, conflicts with FERC's regulations under PURPA, because it limits the utilities' total obligation to purchase electricity. For example, in the case of Pacific Gas & Electric, CPUC limits the utility's total purchase obligation to 218.8 megawatts. CPUC further limits the utilities' total obligation to purchase electricity from different kinds of generation facilities. For example, in the case of Pacific Gas & Electric, CPUC limits the utility's obligation to purchase electricity generated by qualifying solar facilities to 42.9 megawatts. CPUC still further limits the utilities' obligation to enter contracts with qualifying facilities, allowing the utilities to enter into contracts with qualifying solar facilities for only 5 megawatts in each bimonthly period. These limitations on the utilities' purchase obligations conflict with FERC's regulation requiring that "[e]ach electric utility *shall purchase* … *any* energy and capacity which is made available from a qualifying facility." 18 C.F.R. § 292.303(a) (emphasis added). Accordingly, the Re-MAT program's limitation on the utilities' purchase obligations is preempted.

86. Under FERC's regulations, the rate for purchases shall be equal to the utility's avoided costs, 18 C.F.R. § 292.304, and the qualifying facility has the option of choosing from two different ways of calculating avoided costs: "(i) The avoided costs calculated at the time of delivery; or (ii) The avoided costs calculated at the time the obligation is incurred." *Id.* § 292.304(d)(2).

87. CPUC's Re-MAT program purports to implement the second method, the avoided costs calculated at the time the obligation is incurred, but its pricing mechanism is not based on

the *utilities' avoided* costs. Instead, it is intended to reflect the *qualifying facilities' production* costs.

88. Because the Re-MAT program's pricing mechanism results in prices for electricity that do not reflect the utilities' avoided costs, it conflicts with federal regulations. *See Indep. Energy Producers*, 36 F.3d at 857 ("[FERC]'s regulations are clear that the rate to be paid by utilities for electric energy be determined according to the avoided costs to the *utility* of generating that energy or purchasing it elsewhere, and not according to the [qualifying facility's] efficiency."). Therefore, the Re-MAT pricing mechanism is preempted.

89. Moreover, because the Re-MAT pricing mechanism is not authorized by PURPA, it falls outside the narrow exception that Congress has given to states to set rates for wholesale electricity sales. Except for the authority granted by PURPA, states are without power to set rates for wholesale electricity sales; the field of wholesale rate-setting is, with the exception of PURPA, reserved exclusively for FERC. For that reason, too, the Re-MAT pricing mechanism is preempted.

90. CPUC has justified its pricing mechanism on the ground that it "prevents overpayment" to qualifying facilities. May 2012 Order at 18; *id.* at 49-50 (explaining that the Re-MAT program is intended to "minimize ratepayer exposure to a large number of non-competitively priced contracts"); *id.* at 35 (explaining that the purpose of the Re-MAT pricing mechanism is to use "the ability for competition to control contract cost").

91. CPUC's policy reflected in the Orders is in conflict with FERC's policy and stands as an obstacle to the accomplishment and execution of the full purposes of Congress. FERC understood that a utility's avoided costs may well be larger than the cost to a qualifying facility of producing electricity, yet it expressly chose *not* to tie price to qualifying facilities' costs. Rather, FERC adopted a policy under which any difference between a utility's avoided costs and the qualifying facilities' production costs would be paid to the owners and operators of qualifying facilities, rather than allocated among the utilities' customers.

92. In FERC's view, a pricing scheme that would allow qualifying facilities to increase their profit as a result of lowering their costs would encouraging qualifying facilities to

increase their efficiency and promote further reliance on renewable generation technology. In its Order explaining this rationale, FERC noted: "In most instances … purchases of energy or capacity from qualifying facilities will only occur when the cost to the qualifying [facility] … of producing the energy or capacity is lower than the utility's avoided costs. Only if this is the case will payment by the utility of its avoided costs provide economic benefit for the … [qualifying facility]." FERC, Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, 45 Fed. Reg. 12,214, 12,222 (1980). FERC continued: "The Commission notes that, in most instances, if part of the savings from [qualifying facility production] … were allocated among the utilities' ratepayers, any rate reductions will be insignificant for any individual customers. On the other hand, if these savings are allocated to the relatively small class of qualifying [facilities], they may provide a significant incentive for a higher growth rate of these technologies." *Id.* Accordingly, FERC determined that "the basis for the determination of rates for purchases should be the utility's avoided costs and should not vary on the basis of the costs of the particular qualifying facility." *Id.*

93. The Supreme Court considered and affirmed FERC's decision "to set the rate at full avoided cost rather than at a level that would result in direct rate savings for utility customers by permitting a utility to obtain energy at a cost less than the cost to the utility of producing the energy itself or purchasing it from an alternative source." *Am. Paper Inst*,, 461 U.S. at 406. The Court reasoned that, in setting the required rate at the utility's full avoided costs, and not less than that amount, "the Commission considered the relevant factors and deemed it most important at this time to provide the maximum incentive for the development of cogeneration and small power production, in light of the Commission's judgment that the entire country will ultimately benefit from the increased development of these technologies and the resulting decrease in the nation's dependence on fossil fuels." *Id.* at 417.

94. The Ninth Circuit has likewise emphasized FERC's decision to "provide that [qualifying facilities] are entitled to sell electric energy to utilities at a rate that is the utility's *full* avoided costs." *Indep. Energy Producers*, 36 F.3d at 858. The Ninth Circuit explained that "[i]n

implementing its regulations, [FERC] clearly weighed Congress's desire" to promote electricity production by qualifying facilities "while not burdening ratepayers, and concluded that requiring utilities to pay *full* avoided costs properly balanced these interests." *Id.* As the Ninth Circuit explained, "If purchase rates are set at the utility's avoided cost, consumers are not forced to subsidize [qualifying facilities] because they are paying the same amount they would have paid if the utility had generated energy itself or purchased energy elsewhere." *Id.*

95. CPUC, in the Orders, has adopted a policy that conflicts with FERC's and stands as an obstacle to the accomplishment and execution of the full purposes of Congress. CPUC has concluded, in direct conflict with FERC, that consumers would be "overpay[ing]," May 2012 Order at 18, if qualifying facilities received contracts at a price equal to the utilities' avoided costs. Accordingly, it has adopted a pricing mechanism designed to minimize the cost of PURPA contracts, without regard to the utilities' avoided costs. Indeed, CPUC specifically designed the Re-MAT program to "minimize[] costs to ratepayers [and] prevent[] overpayment…" and to "maximize contract value to the ratepayer and the utility by using the market to determine the price…" May 2012 Order at 18; *see also* paragraph 65, *supra*. CPUC's adoption of such a pricing mechanism conflicts with FERC's policy, which mandates that qualifying facilities be paid a price equal to the utilities' avoided costs, regardless of the qualifying facilities' own cost of production. CPUC's orders thus stand as an obstacle to the full achievement of Congress's purpose in enacting PURPA, which is to facilitate renewable energy generation by providing economic incentives for qualifying facilities to enter the market, without making consumers any worse off than they would otherwise be.

96. Because CPUC's Orders conflict with federal regulations under PURPA and are an obstacle to the achievement of Congress' policy in enacting PURPA, and because CPUC has no authority to set wholesale electricity rates other than that given by PURPA, CPUC's Orders are preempted by federal law and violate the Supremacy Clause of the U.S Constitution.

97. Plaintiff will suffer irreparable harm by virtue of CPUC's violation of the Supremacy Clause, because it will continue to be unable to enter into a contract at the long-run

avoided cost price guaranteed by federal law, and is without any adequate remedy at law and no opportunity for compensation for CPUC's violation of the Supremacy Clause.

98. The public interest is also harmed by CPUC's violation of federal law. Congress and FERC have determined that the public interest lies in encouraging the development of renewable energy generation, so long as consumers do not pay more for renewable energy generation than they would for the electricity that would otherwise need to be produced.

99. Plaintiff is entitled to judgment under 28 U.S.C. §§ 2201(a) and 2202, declaring that the CPUC Orders violate the Supremacy Clause (Article VI, Clause 2) of the United States Constitution.

100. Plaintiff is entitled to injunctive relief preventing Defendants from continuing to carry out its unlawful Re-MAT program, and requiring Defendants to promulgate regulations consistent with federal regulations and policy.

101. Such injunctive relief would harm Defendants less (if at all) than denying relief would harm Plaintiff.

PRAYER FOR RELIEF

WHEREFORE, Plaintiffs prays that this Court enter an Order:

a. Declaring that the Orders violate the Supremacy Clause of the U.S. Constitution insofar as they place numerical limits on utilities' obligations to enter into contracts purchasing electricity from qualifying facilities;

b. Declaring that the Orders violate the Supremacy Clause of the U.S. Constitution insofar as they establish a price different than the utility's avoided costs calculated for the length of the contract term at the time the contractual obligation is incurred;

c. Enjoining Defendants from continuing to apply the Re-MAT program as set forth in the Orders;

d. Enjoining Defendants to issue new Orders implementing PURPA in a manner consistent with federal law;

e. Awarding Plaintiff its reasonable attorney fees pursuant to 42 U.S.C. § 1983 and

42 U.S.C. § 1988;

f. Awarding Plaintiff such further relief as the Court may deem just and equitable.

Dated: June 25, 2014

Respectfully submitted,

JENNER & BLOCK LLP

By: /s/ Matthew E. Price
Matthew E. Price (*pro hac vice*)
Attorney for Plaintiff
Email: mprice@jenner.com

APPENDIX TO
SECOND AMENDED COMPLAINT

TABLE OF CONTENTS

TABLE OF ACRONYMS

CPUC	California Public Utilities Commission
FERC	Federal Energy Regulatory Commission
LRAC	Long-run avoided cost
PG&E	Pacific Gas & Electric Company
PURPA	Public Utility Regulatory Policies Act
Re-MAT	Renewable Market Adjusting Tariff
SRAC	Short-run avoided cost

STATUTORY AND REGULATORY PROVISIONS

Federal Power Act

16 U.S.C. § 824 Declaration of policy; application of subchapter

(a) Federal regulation of transmission and sale of electric energy

It is declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation of matters relating to generation to the extent provided in this subchapter and subchapter III of this chapter and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States.

(b) Use or sale of electric energy in interstate commerce

(1) The provisions of this subchapter shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but except as provided in paragraph (2) shall not apply to any other sale of electric energy or deprive a State or State commission of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted across a State line. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.

(2) Notwithstanding subsection (f) of this section, the provisions of sections 824b(a)(2), 824e(e), 824i, 824j, 824j-1, 824k, 824o, 824p, 824q, 824r, 824s, 824t, 824u, and 824v of this title shall apply to the entities described in such provisions, and such entities shall be subject to the jurisdiction of the Commission for purposes of carrying out such provisions and for purposes of applying the enforcement authorities of this chapter with respect to such provisions. Compliance with any order or rule of the Commission under the provisions of section 824b(a)(2), 824e(e), 824i, 824j, 824j-1, 824k, 824o, 824p, 824q, 824r, 824s, 824t, 824u, or 824v of this title, shall not make an electric utility or other entity subject to the jurisdiction of the Commission for any purposes other than the purposes specified in the preceding sentence.

(c) Electric energy in interstate commerce

For the purpose of this subchapter, electric energy shall be held to be transmitted in interstate commerce if transmitted from a State and consumed at any point outside thereof; but only insofar as such transmission takes place within the United States.

(d) "Sale of electric energy at wholesale" defined

The term "sale of electric energy at wholesale" when used in this subchapter, means a sale of electric energy to any person for resale.

(e) "Public utility" defined

The term "public utility" when used in this subchapter and subchapter III of this chapter means any person who owns or operates facilities subject to the jurisdiction of the Commission under this subchapter (other than facilities subject to such jurisdiction solely by reason of section 824e(e), 824e(f), 824i, 824j, 824j-1, 824k, 824o, 824p, 824q, 824r, 824s, 824t, 824u, or 824v of this title).

(f) United States, State, political subdivision of a State, or agency or instrumentality thereof exempt

No provision in this subchapter shall apply to, or be deemed to include, the United States, a State or any political subdivision of a State, an electric cooperative that receives financing under the Rural Electrification Act of 1936 (7 U.S.C. 901 et seq.) or that sells less than 4,000,000 megawatt hours of electricity per year, or any agency, authority, or instrumentality of any one or more of the foregoing, or any corporation which is wholly owned, directly or indirectly, by any one or more of the foregoing, or any officer, agent, or employee of any of the foregoing acting as such in the course of his official duty, unless such provision makes specific reference thereto.

(g) Books and records

(1) Upon written order of a State commission, a State commission may examine the books, accounts, memoranda, contracts, and records of--

(A) an electric utility company subject to its regulatory authority under State law,

(B) any exempt wholesale generator selling energy at wholesale to such electric utility, and

(C) any electric utility company, or holding company thereof, which is an associate company or affiliate of an exempt wholesale generator which sells electric energy to an electric utility company referred to in subparagraph (A),

wherever located, if such examination is required for the effective discharge of the State commission's regulatory responsibilities affecting the provision of electric service.

(2) Where a State commission issues an order pursuant to paragraph (1), the State commission shall not publicly disclose trade secrets or sensitive commercial information.

(3) Any United States district court located in the State in which the State commission referred to in paragraph (1) is located shall have jurisdiction to enforce compliance with this subsection.

(4) Nothing in this section shall--

(A) preempt applicable State law concerning the provision of records and other information; or

(B) in any way limit rights to obtain records and other information under Federal law, contracts, or otherwise.

(5) As used in this subsection the terms “affiliate”, “associate company”, “electric utility company”, “holding company”, “subsidiary company”, and “exempt wholesale generator” shall have the same meaning as when used in the Public Utility Holding Company Act of 2005 [42 U.S.C.A. § 16451 et seq.].

Public Utility Regulatory Policies Act (PURPA)

16 U.S.C. § 824a-3 Cogeneration and small power production

(a) Cogeneration and small power production rules

Not later than 1 year after November 9, 1978, the Commission shall prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production, and to encourage geothermal small power production facilities of not more than 80 megawatts capacity, which rules require electric utilities to offer to--

(1) sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities and

(2) purchase electric energy from such facilities.

Such rules shall be prescribed, after consultation with representatives of Federal and State regulatory agencies having ratemaking authority for electric utilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments. Such rules shall include provisions respecting minimum reliability of qualifying cogeneration facilities and qualifying small power production facilities (including reliability of such facilities during emergencies) and rules respecting reliability of electric energy service to be available to such facilities from electric utilities during emergencies. Such rules may not authorize a qualifying cogeneration facility or qualifying small power production facility to make any sale for purposes other than resale.

(b) Rates for purchases by electric utilities

The rules prescribed under subsection (a) of this section shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase--

(1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and

(2) shall not discriminate against qualifying cogenerators or qualifying small power producers.

No such rule prescribed under subsection (a) of this section shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.

(c) Rates for sales by utilities

The rules prescribed under subsection (a) of this section shall insure that, in requiring any electric utility to offer to sell electric energy to any qualifying cogeneration facility or qualifying small power production facility, the rates for such sale--

(1) shall be just and reasonable and in the public interest, and

(2) shall not discriminate against the qualifying cogenerators or qualifying small power producers.

(d) "Incremental cost of alternative electric energy" defined

For purposes of this section, the term "incremental cost of alternative electric energy" means, with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source.

(e) Exemptions

(1) Not later than 1 year after November 9, 1978, and from time to time thereafter, the Commission shall, after consultation with representatives of State regulatory authorities, electric utilities, owners of cogeneration facilities and owners of small power production facilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments, prescribe rules under which geothermal small power production facilities of not more than 80 megawatts capacity, qualifying cogeneration facilities, and qualifying small power production facilities are exempted in whole or part from the Federal Power Act [16 U.S.C.A. § 791a et seq.], from the Public Utility Holding Company Act [15 U.S.C.A. § 79 et seq.], from State laws and regulations respecting the rates, or respecting the financial or organizational regulation, of electric utilities, or from any combination of the foregoing, if the Commission determines such exemption is necessary to encourage cogeneration and small power production.

(2) No qualifying small power production facility (other than a qualifying small power production facility which is an eligible solar, wind, waste, or geothermal facility as defined in section 3(17)(E) of the Federal Power Act [16 U.S.C. § 796(17)(E)]) which has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), exceeds 30 megawatts, or 80 megawatts for a qualifying small power production facility using geothermal energy as the primary energy source, may be exempted under rules under paragraph (1) from any provision of law or regulation referred to in paragraph (1), except that any qualifying small power production facility which produces electric energy solely by the use of biomass as a primary energy source, may be exempted by the Commission

under such rules from the Public Utility Holding Company Act [15 U.S.C.A. § 79 et seq.] and from State laws and regulations referred to in such paragraph (1).

(3) No qualifying small power production facility or qualifying cogeneration facility may be exempted under this subsection from--

(A) any State law or regulation in effect in a State pursuant to subsection (f) of this section,

(B) the provisions of section 210, 211, or 212 of the Federal Power Act [16 U.S.C.A. § 824i, 824j, or 824k] or the necessary authorities for enforcement of any such provision under the Federal Power Act [16 U.S.C.A. § 791a et seq.], or

(C) any license or permit requirement under part I of the Federal Power Act [16 U.S.C.A. § 791a et seq.], any provision under such Act related to such a license or permit requirement, or the necessary authorities for enforcement of any such requirement.

(f) Implementation of rules for qualifying cogeneration and qualifying small power production facilities

(1) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) of this section or revised under such subsection, each State regulatory authority shall, after notice and opportunity for public hearing, implement such rule (or revised rule) for each electric utility for which it has ratemaking authority.

(2) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) of this section or revised under such subsection, each nonregulated electric utility shall, after notice and opportunity for public hearing, implement such rule (or revised rule).

(g) Judicial review and enforcement

(1) Judicial review may be obtained respecting any proceeding conducted by a State regulatory authority or nonregulated electric utility for purposes of implementing any requirement of a rule under subsection (a) of this section in the same manner, and under the same requirements, as judicial review may be obtained under section 2633 of this title in the case of a proceeding to which section 2633 of this title applies.

(2) Any person (including the Secretary) may bring an action against any electric utility, qualifying small power producer, or qualifying cogenerator to enforce any requirement established by a State regulatory authority or nonregulated electric utility pursuant to subsection (f) of this section. Any such action shall be brought only in the

manner, and under the requirements, as provided under section 2633 of this title with respect to an action to which section 2633 of this title applies.

(h) Commission enforcement

(1) For purposes of enforcement of any rule prescribed by the Commission under subsection (a) of this section with respect to any operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility which are subject to the jurisdiction of the Commission under part II of the Federal Power Act [16 U.S.C.A. § 824 et seq.], such rule shall be treated as a rule under the Federal Power Act [16 U.S.C.A. § 791a et seq.]. Nothing in subsection (g) of this section shall apply to so much of the operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility as are subject to the jurisdiction of the Commission under part II of the Federal Power Act.

(2)

(A) The Commission may enforce the requirements of subsection (f) of this section against any State regulatory authority or nonregulated electric utility. For purposes of any such enforcement, the requirements of subsection (f) (1) of this section shall be treated as a rule enforceable under the Federal Power Act [16 U.S.C.A. § 791a et seq.]. For purposes of any such action, a State regulatory authority or nonregulated electric utility shall be treated as a person within the meaning of the Federal Power Act. No enforcement action may be brought by the Commission under this section other than--

(i) an action against the State regulatory authority or nonregulated electric utility for failure to comply with the requirements of subsection (f) of this section or

(ii) an action under paragraph (1).

(B) Any electric utility, qualifying cogenerator, or qualifying small power producer may petition the Commission to enforce the requirements of subsection (f) of this section as provided in subparagraph (A) of this paragraph. If the Commission does not initiate an enforcement action under subparagraph (A) against a State regulatory authority or nonregulated electric utility within 60 days following the date on which a petition is filed under this subparagraph with respect to such authority, the petitioner may bring an action in the appropriate United States district court to require such State regulatory authority or nonregulated electric utility to comply with such requirements, and such court may issue such injunctive or other relief as may be appropriate. The Commission may intervene as a matter of right in any such action.

(i) Federal contracts

No contract between a Federal agency and any electric utility for the sale of electric energy by such Federal agency for resale which is entered into after November 9, 1978, may contain any provision which will have the effect of preventing the implementation of any rule under this

section with respect to such utility. Any provision in any such contract which has such effect shall be null and void.

(j) New dams and diversions

Except for a hydroelectric project located at a Government dam (as defined in section 3(10) of the Federal Power Act [16 U.S.C.A. § 796(10)]) at which non-Federal hydroelectric development is permissible, this section shall not apply to any hydroelectric project which impounds or diverts the water of a natural watercourse by means of a new dam or diversion unless the project meets each of the following requirements:

(1) No substantial adverse effects

At the time of issuance of the license or exemption for the project, the Commission finds that the project will not have substantial adverse effects on the environment, including recreation and water quality. Such finding shall be made by the Commission after taking into consideration terms and conditions imposed under either paragraph (3) of this subsection or section 10 of the Federal Power Act [16 U.S.C.A. § 803] (whichever is appropriate as required by that Act [16 U.S.C.A. § 791a et seq.] or the Electric Consumers Protection Act of 1986) and compliance with other environmental requirements applicable to the project.

(2) Protected rivers

At the time the application for a license or exemption for the project is accepted by the Commission (in accordance with the Commission's regulations and procedures in effect on January 1, 1986, including those relating to environmental consultation), such project is not located on either of the following:

(A) Any segment of a natural watercourse which is included in (or designated for potential inclusion in) a State or national wild and scenic river system.

(B) Any segment of a natural watercourse which the State has determined, in accordance with applicable State law, to possess unique natural, recreational, cultural, or scenic attributes which would be adversely affected by hydroelectric development.

(3) Fish and wildlife terms and conditions

The project meets the terms and conditions set by fish and wildlife agencies under the same procedures as provided for under section 30(c) of the Federal Power Act [16 U.S.C.A. § 823a(c)].

(k) "New dam or diversion" defined

For purposes of this section, the term "new dam or diversion" means a dam or diversion which requires, for purposes of installing any hydroelectric power project, any construction, or enlargement of any impoundment or diversion structure (other than repairs or reconstruction or the addition of flashboards or similar adjustable devices).

(l) Definitions

For purposes of this section, the terms "small power production facility", "qualifying small power production facility", "qualifying small power producer", "primary energy source", "cogeneration facility", "qualifying cogeneration facility", and "qualifying cogenerator" have the respective meanings provided for such terms under section 3(17) and (18) of the Federal Power Act [16 U.S.C.A. § 796(17), (18)].

(m) Termination of mandatory purchase and sale requirements

(1) Obligation to purchase

After August 8, 2005, no electric utility shall be required to enter into a new contract or obligation to purchase electric energy from a qualifying cogeneration facility or a qualifying small power production facility under this section if the Commission finds that the qualifying cogeneration facility or qualifying small power production facility has nondiscriminatory access to--

(A)(i) independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and (ii) wholesale markets for long-term sales of capacity and electric energy; or

(B)(i) transmission and interconnection services that are provided by a Commission-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers; and (ii) competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or

(C) wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in subparagraphs (A) and (B).

(2) Revised purchase and sale obligation for new facilities

(A) After August 8, 2005, no electric utility shall be required pursuant to this section to enter into a new contract or obligation to purchase from or sell electric energy to a facility that is not an existing qualifying cogeneration facility unless the facility meets the criteria for qualifying cogeneration facilities established by the Commission pursuant to the rulemaking required by subsection (n) of this section.

(B) For the purposes of this paragraph, the term "existing qualifying cogeneration facility" means a facility that--

(i) was a qualifying cogeneration facility on August 8, 2005; or

(ii) had filed with the Commission a notice of self-certification, self recertification or an application for Commission certification under 18 CFR 292.207 prior to the date on which the Commission issues the final rule required by subsection (n) of this section.

(3) Commission review

Any electric utility may file an application with the Commission for relief from the mandatory purchase obligation pursuant to this subsection on a service territory-wide basis. Such application shall set forth the factual basis upon which relief is requested and describe why the conditions set forth in subparagraph (A), (B), or (C) of paragraph (1) of this subsection have been met. After notice, including sufficient notice to potentially affected qualifying cogeneration facilities and qualifying small power production facilities, and an opportunity for comment, the Commission shall make a final determination within 90 days of such application regarding whether the conditions set forth in subparagraph (A), (B), or (C) of paragraph (1) have been met.

(4) Reinstatement of obligation to purchase

At any time after the Commission makes a finding under paragraph (3) relieving an electric utility of its obligation to purchase electric energy, a qualifying cogeneration facility, a qualifying small power production facility, a State agency, or any other affected person may apply to the Commission for an order reinstating the electric utility's obligation to purchase electric energy under this section. Such application shall set forth the factual basis upon which the application is based and describe why the conditions set forth in subparagraph (A), (B), or (C) of paragraph (1) of this subsection are no longer met. After notice, including sufficient notice to potentially affected utilities, and opportunity for comment, the Commission shall issue an order within 90 days of such application reinstating the electric utility's obligation to purchase electric energy under this section if the Commission finds that the conditions set forth in subparagraphs (A), (B) or (C) of paragraph (1) which relieved the obligation to purchase, are no longer met.

(5) Obligation to sell

After August 8, 2005, no electric utility shall be required to enter into a new contract or obligation to sell electric energy to a qualifying cogeneration facility or a qualifying small power production facility under this section if the Commission finds that--

(A) competing retail electric suppliers are willing and able to sell and deliver electric energy to the qualifying cogeneration facility or qualifying small power production facility; and

(B) the electric utility is not required by State law to sell electric energy in its service territory.

(6) No effect on existing rights and remedies

Nothing in this subsection affects the rights or remedies of any party under any contract or obligation, in effect or pending approval before the appropriate State regulatory authority or non-regulated electric utility on August 8, 2005, to purchase electric energy or capacity from or to sell electric energy or capacity to a qualifying cogeneration facility or qualifying small power production facility under this Act (including the right to recover costs of purchasing electric energy or capacity).

(7) Recovery of costs

(A) The Commission shall issue and enforce such regulations as are necessary to ensure that an electric utility that purchases electric energy or capacity from a qualifying cogeneration facility or qualifying small power production facility in accordance with any legally enforceable obligation entered into or imposed under this section recovers all prudently incurred costs associated with the purchase.

(B) A regulation under subparagraph (A) shall be enforceable in accordance with the provisions of law applicable to enforcement of regulations under the Federal Power Act (16 U.S.C. 791a et seq.).

(n) Rulemaking for new qualifying facilities

(1)

(A) Not later than 180 days after August 8, 2005, the Commission shall issue a rule revising the criteria in 18 CFR 292.205 for new qualifying cogeneration facilities seeking to sell electric energy pursuant to this section to ensure--

(i) that the thermal energy output of a new qualifying cogeneration facility is used in a productive and beneficial manner;

(ii) the electrical, thermal, and chemical output of the cogeneration facility is used fundamentally for industrial, commercial, or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as State laws applicable to sales of electric energy from a qualifying facility to its host facility; and

(iii) continuing progress in the development of efficient electric energy generating technology.

(B) The rule issued pursuant to paragraph (1)(A) of this subsection shall be applicable only to facilities that seek to sell electric energy pursuant to this section. For all other purposes, except as specifically provided in subsection (m)(2)(A) of this section, qualifying facility status shall be determined in accordance with the rules and regulations of this Act.

(2) Notwithstanding rule revisions under paragraph (1), the Commission's criteria for qualifying cogeneration facilities in effect prior to the date on which the Commission issues the final rule required by paragraph (1) shall continue to apply to any cogeneration facility that--

(A) was a qualifying cogeneration facility on August 8, 2005, or

(B) had filed with the Commission a notice of self-certification, self-recertification or an application for Commission certification under 18 CFR 292.207 prior to the date on which the Commission issues the final rule required by paragraph (1).

16 U.S.C. § 796 Definitions.

The words defined in this section shall have the following meanings for purposes of this chapter, to wit:

* * *

(17) (A) "small power production facility" means a facility which is an eligible solar, wind, waste, or geothermal facility, or a facility which--

(i) produces electric energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, geothermal resources, or any combination thereof; and

(ii) has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 megawatts;

(B) "primary energy source" means the fuel or fuels used for the generation of electric energy, except that such term does not include, as determined under rules prescribed by the Commission, in consultation with the Secretary of Energy--

(i) the minimum amounts of fuel required for ignition, startup, testing, flame stabilization, and control uses, and

(ii) the minimum amounts of fuel required to alleviate or prevent--

(I) unanticipated equipment outages, and

(II) emergencies, directly affecting the public health, safety, or welfare, which would result from electric power outages;

(C) "qualifying small power production facility" means a small power production facility that the Commission determines, by rule, meets such requirements (including requirements respecting fuel use, fuel efficiency, and reliability) as the Commission may, by rule, prescribe;

(D) "qualifying small power producer" means the owner or operator of a qualifying small power production facility;

(E) "eligible solar, wind, waste or geothermal facility" means a facility which produces electric energy solely by the use, as a primary energy source, of solar energy, wind energy, waste resources or geothermal resources; but only if--

(i) either of the following is submitted to the Commission not later than December 31, 1994:

(I) an application for certification of the facility as a qualifying small power production facility; or

(II) notice that the facility meets the requirements for qualification; and

(ii) construction of such facility commences not later than December 31, 1999, or, if not, reasonable diligence is exercised toward the completion of such facility taking into account all factors relevant to construction of the facility.

* * *

18 C.F.R. § 292.203 General requirements for qualification.

(a) Small power production facilities. Except as provided in paragraph (c) of this section, a small power production facility is a qualifying facility if it:

(1) Meets the maximum size criteria specified in § 292.204(a);

(2) Meets the fuel use criteria specified in § 292.204(b); and

(3) Unless exempted by paragraph (d), has filed with the Commission a notice of self-certification, pursuant to § 292.207(a); or has filed with the Commission an application for Commission certification, pursuant to § 292.207(b)(1), that has been granted.

(b) Cogeneration facilities. A cogeneration facility, including any diesel and dual-fuel cogeneration facility, is a qualifying facility if it:

(1) Meets any applicable standards and criteria specified in §§ 292.205(a), (b) and (d); and

(2) Unless exempted by paragraph (d), has filed with the Commission a notice of self-certification, pursuant to § 292.207(a); or has filed with the Commission an application for Commission certification, pursuant to § 292.207(b)(1), that has been granted.

(c) Hydroelectric small power production facilities located at a new dam or diversion.

(1) A hydroelectric small power production facility that impounds or diverts the water of a natural watercourse by means of a new dam or diversion (as that term is defined in § 292.202(p)) is a qualifying facility if it meets the requirements of:

(i) Paragraph (a) of this section; and

(ii) Section 292.208.

(2) [Reserved]

(d) Exemptions and waivers from filing requirement.

(1) Any facility with a net power production capacity of 1 MW or less is exempt from the filing requirements of paragraphs (a)(3) and (b)(2) of this section.

(2) The Commission may waive the requirement of paragraphs (a)(3) and (b)(2) of this section for good cause. Any applicant seeking waiver of paragraphs (a)(3) and (b)(2) of this section must file a petition for declaratory order describing in detail the reasons waiver is being sought.

18 C.F.R. § 292.207 Procedures for obtaining qualifying status.

(a) Self-certification. The qualifying facility status of an existing or a proposed facility that meets the requirements of § 292.203 may be self-certified by the owner or operator of the facility or its representative by properly completing a Form No. 556 and filing that form with the Commission, pursuant to § 131.80 of this chapter, and complying with paragraph (c) of this section.

(b) Optional procedure--

(1) Application for Commission certification. In lieu of the self-certification procedures in paragraph (a) of this section, an owner or operator of an existing or a proposed facility, or its representative, may file with the Commission an application for Commission certification that the facility is a qualifying facility. The application must be accompanied by the fee prescribed by part 381 of this chapter, and the applicant for Commission certification must comply with paragraph (c) of this section.

(2) General contents of application. The application must include a properly completed Form No. 556 pursuant to § 131.80 of this chapter.

(3) Commission action.

(i) Within 90 days of the later of the filing of an application or the filing of a supplement, amendment or other change to the application, the Commission will either: Inform the applicant that the application is deficient; or issue an order granting or denying the application; or toll the time for issuance of an order. Any order denying certification shall identify the specific requirements which were not met. If the Commission does not act within 90 days of the date of the latest filing, the application shall be deemed to have been granted.

(ii) For purposes of paragraph (b) of this section, the date an application is filed is the date by which the Office of the Secretary has received all of the information and the appropriate filing fee necessary to comply with the requirements of this Part.

(c) Notice requirements--

(1) General. An applicant filing a self-certification, self-recertification, application for Commission certification or application for Commission recertification of the qualifying status of its facility must concurrently serve a copy of such filing on each electric utility with which it expects to interconnect, transmit or sell electric energy to, or purchase supplementary, standby, back-up or maintenance power from, and the State regulatory authority of each state where the facility and each affected electric utility is located. The Commission will publish a notice in the Federal Register for each application for Commission certification and for each self-certification of a cogeneration facility that is subject to the requirements of § 292.205(d).

(2) Facilities of 500 kW or more. An electric utility is not required to purchase electric energy from a facility with a net power production capacity of 500 kW or more until 90 days after the facility notifies the facility that it is a qualifying facility or 90 days after the utility meets the notice requirements in paragraph (c)(1) of this section.

(d) Revocation of qualifying status.

(1)(i) If a qualifying facility fails to conform with any material facts or representations presented by the cogenerator or small power producer in its submittals to the Commission, the notice of self-certification or Commission order certifying the qualifying status of the facility may no longer be relied upon. At that point, if the facility continues to conform to the Commission's qualifying criteria under this part, the cogenerator or small power producer may file either a notice of self-recertification of qualifying status pursuant to the requirements of paragraph (a) of this section, or an application for Commission recertification pursuant to the requirements of paragraph (b) of this section, as appropriate.

(ii) The Commission may, on its own motion or on the motion of any person, revoke the qualifying status of a facility that has been certified under paragraph (b) of this section, if the facility fails to conform to any of the Commission's qualifying facility criteria under this part.

(iii) The Commission may, on its own motion or on the motion of any person, revoke the qualifying status of a self-certified or self-recertified qualifying facility if it finds that the self-certified or self-recertified qualifying facility does not meet the applicable requirements for qualifying facilities.

(2) Prior to undertaking any substantial alteration or modification of a qualifying facility which has been certified under paragraph (b) of this section, a small power producer or cogenerator may apply to the Commission for a determination that the proposed alteration or modification will not result in a revocation of qualifying status. This application for Commission recertification of qualifying status should be submitted in accordance with paragraph (b) of this section.

18 C.F.R. § 292.302 Availability of electric utility system cost data.

(a) Applicability.

(1) Except as provided in paragraph (a)(2) of this section, paragraph (b) applies to each electric utility, in any calendar year, if the total sales of electric energy by such utility for purposes other than resale exceeded 500 million kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year.

(2) Each utility having total sales of electric energy for purposes other than resale of less than one billion kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding year, shall not be subject to the provisions of this section until June 30, 1982.

(b) General rule. To make available data from which avoided costs may be derived, not later than November 1, 1980, June 30, 1982, and not less often than every two years thereafter, each regulated electric utility described in paragraph (a) of this section shall provide to its State regulatory authority, and shall maintain for public inspection, and each nonregulated electric utility described in paragraph (a) of this section shall maintain for public inspection, the following data:

(1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next 5 years;

(2) The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years; and

(3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

(c) Special rule for small electric utilities.

(1) Each electric utility (other than any electric utility to which paragraph (b) of this section applies) shall, upon request:

(i) Provide comparable data to that required under paragraph (b) of this section to enable qualifying facilities to estimate the electric utility's avoided costs for periods described in paragraph (b) of this section; or

(ii) With regard to an electric utility which is legally obligated to obtain all its requirements for electric energy and capacity from another electric utility, provide the data of its supplying utility and the rates at which it currently purchases such energy and capacity.

(2) If any such electric utility fails to provide such information on request, the qualifying facility may apply to the State regulatory authority (which has ratemaking authority over the electric utility) or the Commission for an order requiring that the information be provided.

(d) Substitution of alternative method.

(1) After public notice in the area served by the electric utility, and after opportunity for public comment, any State regulatory authority may require (with respect to any electric utility over which it has ratemaking authority), or any non-regulated electric utility may provide, data different than those which are otherwise required by this section if it determines that avoided costs can be derived from such data.

(2) Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated utility which requires such different data shall notify the Commission within 30 days of making such determination.

(e) State Review.

(1) Any data submitted by an electric utility under this section shall be subject to review by the State regulatory authority which has ratemaking authority over such electric utility.

(2) In any such review, the electric utility has the burden of coming forward with justification for its data.

18 C.F.R. § 292.303 Electric utility obligations under this subpart.

(a) Obligation to purchase from qualifying facilities. Each electric utility shall purchase, in accordance with § 292.304, unless exempted by § 292.309 and § 292.310, any energy and capacity which is made available from a qualifying facility:

(1) Directly to the electric utility; or

(2) Indirectly to the electric utility in accordance with paragraph (d) of this section.

(b) Obligation to sell to qualifying facilities. Each electric utility shall sell to any qualifying facility, in accordance with § 292.305, unless exempted by § 292.312, energy and capacity requested by the qualifying facility.

(c) Obligation to interconnect.

(1) Subject to paragraph (c)(2) of this section, any electric utility shall make such interconnection with any qualifying facility as may be necessary to accomplish purchases or sales under this subpart. The obligation to pay for any interconnection costs shall be determined in accordance with § 292.306.

(2) No electric utility is required to interconnect with any qualifying facility if, solely by reason of purchases or sales over the interconnection, the electric utility would become subject to regulation as a public utility under part II of the Federal Power Act.

(d) Transmission to other electric utilities. If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which such energy or capacity is transmitted shall purchase such energy or capacity under this subpart as if the qualifying facility were supplying energy or capacity directly to such electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to § 292.304(e)(4) and shall not include any charges for transmission.

(e) Parallel operation. Each electric utility shall offer to operate in parallel with a qualifying facility, provided that the qualifying facility complies with any applicable standards established in accordance with § 292.308.

18 C.F.R. § 292.304 Rates for purchases.

(a) Rates for purchases.

(1) Rates for purchases shall:

(i) Be just and reasonable to the electric consumer of the electric utility and in the public interest; and

(ii) Not discriminate against qualifying cogeneration and small power production facilities.

(2) Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.

(b) Relationship to avoided costs.

(1) For purposes of this paragraph, “new capacity” means any purchase from capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978.

(2) Subject to paragraph (b)(3) of this section, a rate for purchases satisfies the requirements of paragraph (a) of this section if the rate equals the avoided costs determined after consideration of the factors set forth in paragraph (e) of this section

(3) A rate for purchases (other than from new capacity) may be less than the avoided cost if the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or the nonregulated electric utility determines that a lower rate is consistent with paragraph (a) of this section, and is sufficient to encourage cogeneration and small power production.

(4) Rates for purchases from new capacity shall be in accordance with paragraph (b)(2) of this section, regardless of whether the electric utility making such purchases is simultaneously making sales to the qualifying facility.

(5) In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this subpart if the rates for such purchases differ from avoided costs at the time of delivery.

(c) Standard rates for purchases.

(1) There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.

(2) There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts.

(3) The standard rates for purchases under this paragraph:

(i) Shall be consistent with paragraphs (a) and (e) of this section; and

(ii) May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(d) Purchases “as available” or pursuant to a legally enforceable obligation. Each qualifying facility shall have the option either:

(1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

(2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:

(i) The avoided costs calculated at the time of delivery; or

(ii) The avoided costs calculated at the time the obligation is incurred.

(e) Factors affecting rates for purchases. In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:

(1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;

(2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the utility to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

(f) Periods during which purchases not required.

(1) Any electric utility which gives notice pursuant to paragraph (f)(2) of this section will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.

(2) Any electric utility seeking to invoke paragraph (f)(1) of this section must notify, in accordance with applicable State law or regulation, each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the electric utility.

(3) Any electric utility which fails to comply with the provisions of paragraph (f)(2) of this section will be required to pay the same rate for such purchase of energy or capacity as would be required had the period described in paragraph (f)(1) of this section not occurred.

(4) A claim by an electric utility that such a period has occurred or will occur is subject to such verification by its State regulatory authority as the State regulatory authority determines necessary or appropriate, either before or after the occurrence.

144 FERC ¶ 61,122, 2013 WL 4053221

FEDERAL ENERGY REGULATORY COMMISSION

Winding Creek Solar LLC

Docket Nos. EL13-71-000, QF13-403-001

NOTICE OF INTENT NOT TO ACT

(Issued August 12, 2013)

1. On June 13, 2013, Winding Creek Solar LLC (Winding Creek) filed a petition for enforcement against the California Public Utilities Commission (California Commission) for enforcement pursuant to section 210(h)(2)(B) of the Public Utility Regulatory Policies Act of 1978 (PURPA). [FN1] Winding Creek petitions the Commission to initiate an enforcement action against the California Commission to remedy part of the California Commission's feed-in tariff program, called the renewable market adjusting tariff, which Winding Creek alleges is inconsistent with PURPA.

2. Notice is hereby given that the Commission declines to initiate an enforcement action pursuant to section 210(h)(2)(A) of PURPA. [FN2] Our decision not to initiate an enforcement action means that the Petitioners may themselves bring an enforcement action against the California Commission in the appropriate court. [FN3]

By the direction of the Commission.
Kimberly D. Bose
Secretary

FN1. 16 U.S.C. § 824a-3(h)(2)(B) (2006).

FN2. 16 U.S.C. § 824a-3(h)(2)(A) (2006).

FN3. 16 U.S.C. § 824a-3(h)(2)(B) (2006).

EXHIBIT A

ALJ/RMD/jt2 **Date of Issuance 5/31/2012**

Decision 12-05-035 May 24, 2012

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	Rulemaking 11-05-005 (Filed May 5, 2011)

DECISION REVISING FEED-IN TARIFF PROGRAM, IMPLEMENTING AMENDMENTS TO PUBLIC UTILITIES CODE SECTION 399.20 ENACTED BY SENATE BILL 380, SENATE BILL 32, AND SENATE BILL 2 1X
AND
DENYING PETITIONS FOR MODIFICATION OF DECISION 07-07-027 BY SUSTAINABLE CONSERVATION AND SOLUTIONS FOR UTILITIES, INC.

Table of Contents

Title **Page**

Table of Contents (cont.)

Title **Page**

Table of Contents (cont.)

DECISION REVISING FEED-IN TARIFF PROGRAM, IMPLEMENTING AMENDMENTS TO PUBLIC UTILITIES CODE SECTION 399.20 ENACTED BY SENATE BILL 380, SENATE BILL 32, AND SENATE BILL 2 1X AND DENYING PETITIONS FOR MODIFICATION OF DECISION 07-07-027 BY SUSTAINABLE CONSERVATION AND SOLUTIONS FOR UTILITIES, INC.

1. Summary

Today's decision implements the amendments to Pub. Util. Code § 399.20[1] enacted by Senate Bill (SB) 380 (Kehoe, Stats. 2008, ch. 544, § 1), SB 32 (Negrete McLeod, Stats. 2009, ch. 328, § 3.5), and the more recent amendments enacted by SB 2 of the 2011-2012 First Extraordinary Session (Simitian, Stats. 2011, ch. 1) (SB 2 1X).

Notably, in implementing the statutory amendments to § 399.20, this decision adopts, among other things, a new pricing mechanism for the Commission's § 399.20 Feed-in Tariff (FiT) Program. This new pricing mechanism will be referred to as the "Renewable Market Adjusting Tariff" or "Re-MAT." Re-MAT includes two principle components. First, a starting price based on the weighted average contract price of Pacific Gas and Electric Company, Southern California Electric Company, and San Diego Gas & Electric Company's highest priced executed contract resulting from the Commission's Renewable Auction Mechanism auction held in November 2011. This starting price will apply to three FiT product types: baseload, peaking as-available, and non-peaking as-available.[2] Second, we adopt a two-month price adjustment mechanism that may increase or decrease the price for each product type every

[1] All statutory references are to the Public Utilities Code unless otherwise indicated.

[2] The term "as-available" is used interchangeably with the term "intermittent."

two months based on the market response. Finally, each accepted project will be paid a time-of-delivery adjustment based on the generator's actual energy delivery profile and the individual utility's time-of-delivery factors.

Today's decision also adopts several new or revised FiT Program components, including, among other things, increasing the maximum size of eligible facilities to 3 megawatts, adjusting capacity allocations among the utilities, adopting project viability criteria, and excluding small electric utilities from the program.

Lastly, this decision denies two petitions for modification of Decision 07-07-027, the decision initially establishing the tariffs and standard contracts for utilities under § 399.20, filed by Sustainable Conservation and by Solutions for Utilities, Inc.

This proceeding remains open.

2. Background

Today's decision focuses on implementing those aspects of the Renewables Portfolio Standard Program (RPS Program) under § 399.11 *et seq.* relevant to smaller renewable generation projects commonly referred to as distributed generation. Specifically, today's decision focuses on § 399.20.[3] This code section declares the Legislature's intent and the policy of the state to encourage electrical generation from small distributed generation that qualifies as "eligible renewable energy resources" under the RPS Program with an effective capacity of 3 megawatts (MW) or less and, among other things, strategically located on the

[3] All references to § 399.20 are to that section as amended by Senate Bill (SB) 380 (Stats. 2008, Ch.544), SB 32 (Stats. 2009. Ch.328), and SB 2 1X (2011-2012 First Extraordinary Session, Stats. 2011, Ch.1) unless otherwise noted.

distribution grid.[4] Today's decision refers to the Commission's ongoing implementation work under § 399.20 as the § 399.20 Feed-in Tariff (FiT) Program.

2.1. Legislative History – § 399.20

In 2002, the Legislature enacted SB 1078 (Sher, Stats. 2002, ch. 516), to be effective on January 1, 2003, to establish the RPS Program (Article 16, commencing with § 399.11, of the Pub. Util. Code) and to, among other things, increase the amount of electricity procured per year from eligible renewable energy resources, as defined therein, to an amount that equaled at least 20% of the total electricity sold to retail customers in the state by December 31, 2017. The Legislature accelerated this goal to 20% by 2010 in SB 107 (Simitian, Stats. 2006, ch. 464). In 2011, the Legislature extended and increased the state's goal under the RPS Program to 33% of the total electricity sold to retail customers in the state by December 31, 2020.[5]

The code section relevant to today's decision, § 399.20, was initially added to the Pub. Util. Code by Assembly Bill (AB) 1969 (Yee, Stats. 2006, ch. 731), to be effective on January 1, 2007. The provisions of § 399.20 are part of the RPS Program and, importantly, under § 399.20, every kilowatt hour (kWh) of electricity purchased from an electric generation facility counts toward meeting an electric corporations' RPS Program procurement quantity requirements under SB 2 1X of 33% by 2020.[6]

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[4] *See* § 399.20(a) and (b)(1)-(4).

[5] *See generally*, SB 2 1X.

[6] More details regarding the RPS Program's compliance periods and quantity requirements under SB 2 1X are set forth in D.11-12-020 (*Decision Setting Procurement Quantify Requirements for Retail Sellers for the Renewables Portfolio Standard Program*).

As initially enacted by AB 1969, § 399.20 created the renewable FiT Program. This program has since been expanded by the Legislature and the Commission. Under AB 1969, electrical corporations were required to make a tariff or standard contract available only to public water and wastewater customers on a first-come, first-served basis until the electrical corporation met its proportionate share of a 250 MW statewide procurement limit.

Since 2007, the Legislature has adopted several amendments to this code section, including SB 380, SB 32, and SB 2 1X, and the Commission has adopted Decision (D.) 07-07-027, implementing the Commission's § 399.20 FiT Program as set forth in AB 1969. Today's decision builds upon D.07-07-027 by modifying the Commission's existing § 399.20 FiT Program. Specifically, today's decision addresses the amendments to § 399.20 enacted by SB 380, SB 32, and SB 2 1X.[7]

The amendments to § 399.20 set forth in SB 380, SB 32, and SB 2 1X cover a broad range of issues, including increasing the maximum project size to 3 MW from 1.5 MW. Some of the most controversial issues relate to price. Many of these provisions must be memorialized in a contract, also referred to as a power purchase agreement, between the utility and the generator. We will address some of the terms of these contracts under § 399.20, as amended, in today's decision. More specific terms and conditions will be addressed in a subsequent decision in this proceeding, which will focus exclusively on the Commission's

[7] SB 380 was enacted by the Legislature in September 2008 to be effective January 1, 2009; SB 32 was enacted by the Legislature in 2009 to be effective January 1, 2010, and SB 2 1X was enacted by the Legislature in 2011 to be effective on December 10, 2011. SB 2 1X, enacted in the 2011-2012 First Extraordinary Session of the Legislature, went into effect on the 91st day after adjournment of the special session at which the bill was passed. (Gov't. Code § 9600(a).) The 2011-2012 First Extraordinary Session adjourned on September 10, 2011, making SB 2 1X effective on December 10, 2011.

adoption of a single standard form contract for the § 399.20 FiT Program.[8] We also note that generation projects seeking to participate in the § 399.20 FiT Program must enter into an interconnection agreement. We will address some of the interconnection issues referred to in § 399.20, as amended, in today's decision. However, the majority of the issues related to interconnection under the § 399.20 FiT Program will be addressed in a separate, ongoing Commission proceeding , Rulemaking (R.) 11-09-011,[9] which, among other things, "seeks to review, and if necessary revise Rule 21 to ensure that the interconnection process is timely, non-discriminatory, cost-effective, and transparent."[10]

2.2. Feed-In Tariff Program - Decision 07-07-027

The Commission implemented AB 1969 in 2007 through D.07-07-027 for eligible facilities up to 1.5 MW. Although § 399.20 only applied to a narrowly defined group of customers, specifically public water and wastewater facilities,

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[8] *See, Joint Assigned Commissioner's and Administrative Law Judge's Ruling Setting Workshop on a Utility Standard Form Contract for the Section 399.20 Feed-In Tariff Program, dated January 10, 2012* (This ruling directed the utilities to collaborate to create one uniform contract for the program. The Commission held a workshop to review the contract on February 22, 2012 and will address this matter in a subsequent decision.) All rulings and pleadings filed in this proceeding are available at the "Docket Card" link for this rulemaking at www.cpuc.ca.gov.

[9] R.11-09-011, *Order Instituting Rulemaking on the Commission's own motion to improve distribution level interconnection rules and regulations for certain classes of electric generators and electric storage resources* (adopted on September 22, 2012). A proposed settlement was filed in the interconnection proceeding on March 16, 2012 that offers a consensus-based reform of Electric Rule 21, the interconnection tariff under this Commission's jurisdiction. The complete *Motion for Approval of Settlement Agreement Revising Distribution level Interconnection Rules and Regulations,* including the proposed revised Rule 21, is available at http://docs.cpuc.ca.gov/EFILE/MOTION/162852.PDF. The Commission is presently considering the proposed settlement.

[10] R.11-09-011 at 2.

D.07-07-027 extended the program under § 399.20 to a broader group of eligible customers in Pacific Gas and Electric Company's (PG&E) and Southern California Edison Company's (SCE) service territories. D.07-07-027 directed San Diego Gas & Electric Company (SDG&E), PG&E, and SCE to file tariffs with a fixed price for public water and wastewater facilities and, in addition, directed PG&E and SCE to file similar tariffs for all customers in their service territories. Approximately a year later, in D.08-09-033, the Commission directed SDG&E to file a tariff extending § 399.20 to all customers in its service territory.

Consistent with the then-existing statutory requirements under AB 1969, then codified in § 399.20(5)(d), D.07-07-027 adopted the Market Price Referent (MPR) as the § 399.20 FiT Program price. The MPR was designed by the Commission to reflect the long-term ownership, operating, and fixed-price fuel costs for a new 500 MW natural gas-fired combined cycle gas turbine.[11] The MPR calculates a levelized price for a proxy baseload combined cycle gas turbine using a cash flow modeling approach. The inputs for the MPR model include installed capital costs, fixed and variable operations and maintenance costs, natural gas fuel costs, cost of capital, and environmental permitting and compliance costs. The model produces several MPR values based on a facility's online date and contract term length (e.g., 10, 15, or 20 years). Under the Commission's adopted methodology, the appropriate MPR value for a particular RPS project is adjusted to account for the value of different electricity products

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[11] The Commission set the initial parameters for the MPR in D.03-06-071. The method for calculating the MPR was first developed in D.04-06-015. In D.05-12-042, the methodology for calculating the MPR was expanded and stabilized. The Commission subsequently updated the MPR methodology in D.08-10-026.

(e.g., baseload, peaking, and as-available) by applying the individual utility's time-of-delivery factors.

Starting in 2004, the Commission has calculated a MPR for each RPS solicitation.[12] The Commission's most recently calculated and adopted MPR, referred to as the 2011 MPR, is found in Resolution E-4442 (issued on December 6, 2011).[13] In terms of pricing for the FiT Program under the MPR, the 2011 MPR, for example, would pay a generator that came online in 2013 with a 20-year contract at $93.75 per megawatt hour (MWh) pre time-of-delivery adjustments. Among other things, Resolution E-4442 ordered each utility to update its tariffs for the § 399.20 FiT Program, as required by D.07-07-027, consistent with the 2011 MPR.[14]

Utilities filed tariffs adopting the 2011 MPR as the price for their § 399.20 FiT Program on or about December 8, 2011.[15] These December tariff filings reduced the prices under the FiT Program from, for example, $108.98/MWh to $93.75/MWh pre time-of-delivery adjustments for a generator that came online

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12 R.04-04-026, *Assigned Commissioner's Ruling Disclosing Market Price Referents for the Renewables Portfolio Standard Program*, dated February 11, 2005.

13 Resolution E-4442 provides "the adopted 2011 MPR values establish the prices, effective January 3, 2011, for the renewable energy FiT program set forth in Public Utilities Code section 399.20."

14 Ordering Paragraph 2 of Resolution E-4442 provides as follows: "Each electric corporation obligated under Decision 07-07-027, pursuant to Public Utilities Code Section 399.20, shall file a Tier 1 advice letter updating its relevant tariffs and standard contracts with the 2011 market price referent. The advice letter shall be filed and served within 7 days of the effective date of this resolution. The advice letter will have an effective date of January 3, 2012."

15 These filings include Advice Letters 2310-E (SDG&E), 3964-E (PG&E), 2670-E (SCE), 13-E (California Pacific Electric Company, LLC), 460-E (PacifiCorp dba Pacific Power), and 261-E (Bear Valley Electric Service).

in 2013 with a 20-year contract.[16] These recently filed tariffs are the effective prices for the existing FiT Program until modified by this decision and any related tariff filings by the utilities.

2.3. Rulemaking 11-05-005

This proceeding, R.11-05-005, succeeds R.08-08-009 and incorporates the entire record of R.08-08-009. More than 40 parties filed comments to the Commission's Order Instituting Rulemaking for R.11-05-005 on May 31, 2011 and June 9, 2011. An initial prehearing conference regarding amendments to the FiT Program was held on June 13, 2011. The assigned Commissioner issued a scoping memo ruling pursuant to Rule 7.3 of the Commission's Rules of Practice and Procedure on July 8, 2011.

The scoping memo ruling noted that SB 2 1X made significant changes to the overall RPS Program and identified the four "highest priority" issues for immediate attention in the Commission's implementation of SB 2 1X. One of these four issues is the Commission's implementation of the amendments to § 399.20, as set forth in SB 32 and SB 2 1X, and applicable to the FiT Program. Parties provided substantial input to the Commission on the topic of § 399.20 and the amendments thereto. Parties filed briefs in March 2011 in the predecessor proceeding, R.08-08-009. These briefs were filed in response to a ruling by the Administrative Law Judge (ALJ) entitled, *ALJ's Ruling Regarding Setting Schedule for Briefs on Implementation of Senate Bell 32*, dated January 27, 2011. In July and

[16] The 2011 MPR is lower than the 2009 MPR due, primarily, to a drop in natural gas prices from 2009 to 2011. Approximately 75% of the MPR calculation is driven by the price of natural gas. The 2011 MPR superseded the 2009 MPR because the Commission did not calculate an MPR in 2010. As a result, the 2009 MPR continued to be effective until the issuance of Resolution E-4442.

August 2011, parties filed further comments on the § 399.20 FiT Program in response to the *ALJ's Ruling Setting Forth Implementation Proposal for SB 32 and SB 2 1X Amendments to Section 399.20*, dated June 27, 2011. Then, the Commission's Energy Division Staff issued a proposal on pricing and other aspects of § 399.20, which was subsequently entered into the record and commented upon by parties. In today's decision, we refer to this October 13, 2011 Staff Proposal as the "Renewable FiT Staff Proposal."

Taking into consideration the record of this proceeding, consisting of party briefs, comments, the Renewable FiT Staff Proposal, and other evidence, we implement the provisions of § 399.20, as amended.

3. Parameters in Implementing the § 399.20 Feed-In Tariff Program, as Amended

In implementing the amendments to the § 399.20 FiT Program, we rely on federal law, specifically, avoided cost under the Public Utility Regulatory Policies Act of 1978 (PURPA).[17] We also rely upon the state laws governing statutory construction. In addition, we rely on the policy guidelines set forth in the June 27, 2011 ALJ ruling.

3.1. Federal Law – Avoided Cost

In implementing § 399.20, as amended, we necessarily comply with the provisions of Federal Power Act § 205 and § 206, which grant exclusive jurisdiction to the Federal Energy Regulatory Commission (FERC) to regulate wholesale sales of electricity in interstate commerce.

[17] PURPA is codified in scattered sections of 16 U.S.C., including, § 796, § 824a-3 and §§ 2601, *et seq.*

The primary exception to FERC's authority over wholesale rates is established by PURPA. PURPA authorizes state public utilities commissions to establish the wholesale rate, as long as it is an avoided cost for utilities' wholesale purchases from Qualifying Facilities (QFs).[18] FERC gives wide latitude to state public utilities commissions in defining the avoided cost of generation. In general, QFs are alternative energy power production facilities that are primarily renewable or gas-fired cogeneration units.[19]

The modifications to the § 399.20 FiT Program adopted today comply with federal law by requiring, among other things, that all FERC jurisdictional generators[20] participating in the program register with the FERC as QFs[21] and by adopting a price consistent with PURPA, including the most recent guidance provided by the FERC regarding avoided costs pricing for QFs on October 21, 2010 in *California Public Utilities Commission* (2010) 133 FERC ¶61,059 (*FERC Clarification Order*).

We recently addressed the *FERC Clarification Order* and avoided cost under federal law in D.11-04-033.[22] We find the following excerpt from D.11-04-033,

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18 *See* 16 U.S.C. § 824a-3(b); 18 C.F.R. § 292.304(a)(2).

19 *See* 18 C.F.R. § 292.304(a).

20 California Public Utilities Commission, 132 FERC ¶ 61,047 (2010) ¶ 71; (FERC has stated that non-jurisdictional public entity sellers are not subject to restrictions imposed under PURPA, although they may voluntarily choose to become QFs.)

21 Whether QF certification is required for generators participating in the § 399.20 FiT program is discussed separately, herein.

22 D.11-04-033 (*Order Granting Limited Rehearing of Decision 10-12-055 on the Issue of GHG Compliance Costs, Modifying Decision, Denying Rehearing of Decision, as Modified, and Denying Motion to Stay*) at 7. This decision is the final decision implementing the Combined Heat and Power FiT as authorized by AB 1613.

citing to the *FERC Clarification Order*, particularly instructive today as we adopt a new pricing methodology for the FiT Program:

> In this order [*FERC Clarification Order*], FERC clarified that the state has a wide degree of latitude in setting avoided cost, can utilize a multi-tiered avoided cost rate structure, and that this approach is consistent with the avoided cost requirements set forth in Section 210 of PURPA. (*Id.* at pp. 24 & 30.) FERC also clarified that state procurement obligations can be considered when calculating avoided cost, and it specifically overruled its prior holding from *SoCal Edison* to the extent its current determination was inconsistent with that clarification. (*Id.* at pp 29-30 *referring to SoCal Edison* (1995) 71 FERC ¶ 61,269 at 62,080.)[23]

As we found in D.11-04-033, FERC has affirmed a state's ability to "determine that capacity is being avoided, and … rely on the cost of such avoided capacity to determine the avoided cost rate."[24] FERC stated:

> Further, in determining the avoided cost rate, just as a state may take into account the cost of the next marginal unit of generation, so as well the state may take into account obligations imposed by the state that, for example, utilities purchase energy from particular sources of energy or for a long duration.[25]

Based on the *FERC Clarification Order*, we determined in D.11-04-033 that we have a wide degree of latitude in setting the avoided cost. We apply the same logic for the § 399.20 FiT Program. Specifically, based on FERC's clarification, the Commission can determine a different avoided cost, differentiated for particular sources of energy as long as state law has imposed an obligation on the utility to

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23 D.11-04-033 at 7.

24 *Id*. at 11, *citing to FERC Clarification Order* at 26.

25 *FERC Clarification Order* at 26.

purchase energy from those sources of energy. Thus the Commission can have multiple different avoided costs, and we need not be restricted by the avoided cost adopted in D.10-12-035.[26] In addition, the Commission can utilize a multi-tiered avoided cost rate structure. This clarification increases the pricing options the Commission can consider when determining the § 399.20 FiT Program price.

3.2. State Law – the Commission's Fundamental Responsibility and § 399.20

Under §§ 701, 728, and 761, the Commission's fundamental responsibility is to oversee the utility's provision of an adequate supply of safe and reliable electricity at just and reasonable rates. Today, in implementing the statutory amendments to § 399.20, we are guided by, among other things, the Commission's fundamental responsibility and the rules of statutory construction, as discussed below.

3.2.1. Rules of Statutory Construction

In comments in response to the June 27, 2011 ALJ ruling, the Center for Energy Efficiency and Renewable Technologies (CEERT) pointed to the need for the Commission to follow the rules of statutory construction and to take into consideration the legislative intent incorporated into § 399.20. We consider these sources and give each the appropriate weight in implementing the statutory amendments to § 399.20.

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[26] Opinion Adopting Proposed Settlement, (December 12, 2010) in R.06-02-013, R.04-04-003, R.04-04-025, R.99-11-022, *Application of Southern California Edison Company (U338E) for Applying the Market Index Formula and As-Available Capacity Prices adopted in D.07-09-040 to Calculate Short-Run Avoided Cost for Payments to Qualifying Facilities beginning July 2003 and Associated Relief; and Related Matters*.

We give primary weight to the rules of statutory construction as the primary task of this decision is to implement new statutory provisions. The California Supreme Court has enunciated clear standards for courts or state agencies construing a statute. The Commission must act as follows:

> . . . look to the statute's words and give them their usual and ordinary meaning. The statute's plain meaning controls the court's interpretation unless its words are ambiguous. If the statutory language permits more than one reasonable interpretation, courts may consider other aids, such as the statute's purpose, legislative history, and public policy. . . .
>
> Where more than one statutory construction is arguably possible, our policy has long been to favor the construction that leads to the more reasonable result. This policy derives largely from the presumption that the Legislature intends reasonable results consistent with the apparent purpose of the legislation.[27]

Although the courts remain the ultimate arbiters of statutory meaning, courts accord deference to the Commission's reasonable interpretation of statutes.[28] We apply these rules of statutory construction below as we interpret and implement the provisions, as amended, of § 399.20.

As noted in the above quoted excerpt, we are also guided by legislative findings, including, for example, Historical and Statutory Notes. CEERT's comments emphasize the importance of legislative history when implementing SB 32 and SB 2 1X. However, the rules of statutory construction, as set forth above, direct us to look first to the language of the statute itself and we give

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[27] *Imperial Merchant Services, Inc. v. Hunt* (2009) 47 Cal.4th 381, 387-388; *see also, e.g., People v. Canty* (2004) 32 Cal.4th 1266, 1276 and *Lungren v. Deukmejian* (1988) 45 Cal.3d 727, 735.

[28] *Greyhound Lines, Inc. v. Public Utilities Commission* (1968) 68 Cal.2d 406, 410; *Lockyer v. City and County of San Francisco* (2004) 33 Cal.4th 1055, 1090-1091.

those words their usual and ordinary meaning. "If there is no ambiguity in the language of the statute, 'then the legislature is presumed to have meant what it said, and the plain meaning of the language governs.'"[29]

In this manner, today's decision applies the rules of statutory construction in implementing SB 380, SB 32, and SB 2 1X.

3.2.2. Senate Bill 2 1X and Feed-In Tariff Pricing Considerations

Most significantly for purposes of the § 399.20 FiT Program, SB 32 and SB 2 1X provided new direction to the Commission on how to determine the market price for the § 399.20 FiT Program.

SB 2 1X amended § 399.20(d), the statutory provision which sets the program's price, by removing the cross reference to now repealed § 399.15. Under the previously existing cross reference to § 399.15, D.07-07-027 established that the price for electricity purchased under § 399.20 was necessarily tied to the MPR, which was used to set a cost limitation on the RPS Program.[30] Specifically, in D.07-07-027 the Commission found that the pricing for electric generation under § 399.20 was the MPR,[31] adjusted for time-of-delivery factors.[32] Since the

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[29] *Smith v. Rae-Venter Law Group* (2002) 29 Cal.4th 345, 358.

[30] Under SB 1078, the MPR was initially established to provide an RPS contract price reasonableness benchmark and to serve a role in the cost containment mechanism. SB 1036 (Perata) modified the use of the MPR to be only part of the cost-containment mechanism by establishing a limited above-MPR fund for contracts whose price exceeded the MPR.

[31] The Commission previously defined "market price" in D.03-06-071 and D.04-06-015 to be the MPR. More information on the MPR can be found at http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr.

[32] D.07-07-027 at 23-24. Regarding time-of-delivery factors, each utility determines these factors based on its analysis of the forward value of energy and capacity during

Footnote continued on next page

cross-reference to § 399.15 has been removed pursuant to SB 2 1X, electricity purchased under § 399.20 is no longer tied to the MPR as it was calculated for purposes of the larger RPS Program. Thus, the potential range of pricing outcomes for the § 399.20 FiT Program has expanded.

The SB 2 1X amendment to the pricing provisions provides, in pertinent part:[33]

> (d)(1) The tariff shall provide for payment for every kilowatt hour of electricity purchased from an electric generation facility for a period of 10, 15, or 20 years, as authorized by the commission. The payment shall be the market price determined by the commission pursuant to ~~Section 399.15~~ *paragraph (2)* and shall include all current and anticipated environmental compliance costs, including, but not limited to, mitigation of emissions of greenhouse gases and air pollution offsets associated with the operation of new generating facilities in the local air pollution control or air quality management district where the electric generation facility is located. *(2) The commission shall establish a methodology to determine the market price of electricity for terms corresponding to the length of contracts with an electric generation facility, in consideration of the following: (A) The long-term market price of electricity for fixed price contracts, determined pursuant to an electrical corporation's general procurement activities as authorized by the commission. (B) The long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities. (C) The value of different electricity products including baseload, peaking, and as-available electricity. (3) The commission may adjust the payment rate to reflect the value of every kilowatt hour of electricity generated on a time-of-delivery basis. (4) The*

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different times of day and times of the year. This results, in practice, in each utility valuing electricity at different hours differently. As relevant to the MPR calculation under existing tariffs, the three large utilities use between six and nine time-of-delivery periods.

[33] New statutory language is identified with italics and the deleted language is identified in strikeout.

> *commission shall ensure, with respect to rates and charges, that ratepayers that do not receive service pursuant to the tariff are indifferent to whether a ratepayer with an electric generation facility receives service pursuant to the tariff.*

For these reasons, under the recent statutory amendments, we can review the pricing options for renewable distributed generation for the § 399.20 FiT Program under a much broader framework.

In the most basic terms, SB 2 1X directs the Commission to consider the following when adopting a pricing methodology:

(1) Market price determined by the Commission (§ 399.20(d)(1));

(2) Long-term market price for fixed price contracts pursuant to an electrical corporation's general procurement activities (§ 399.20(d)(2)(A));

(3) Long term ownership, operating and fixed-price fuel costs (§ 399.20(d)(2)(B));

(4) Value of electricity products, e.g., base load, peaking, and as-available (§ 399.20(d)(2)(C));

(5) Kilowatt hour price (§ 399.20(d)(1));

(6) 10, 15, or 20 year contract terms (§ 399.20(d)(1));

(7) All current and anticipated environmental compliance costs, including, but not limited to, mitigation of emissions of greenhouse gases and air pollution offsets associated with the operation of new generating facilities in the local air pollution control or air quality management district where the electric generation facility is located (§ 399.20(d)(1));

(8) and two optional inputs, as follows:

- time-of-delivery (§ 399.20(d)(3)); and
- a value for an electric generation facility located on a distribution circuit that generates electricity at a time and in a manner so as to offset the peak demand on the distribution circuit. (§ 399.20(e)).

Our analysis of the pricing proposals must include other provisions of § 399.20, which, while not directly addressing price, impact the structure of the program. These provisions of the statute include, for example, the requirement that generators be "strategically located," that the tariff be offered on a "first-come-first-served basis," and that "ratepayers that do not receive service pursuant to the tariff are indifferent to whether a ratepayer with an electrical generation facility receives service pursuant to the tariff."

3.3. Policy Guidelines

This decision establishes five core policy guidelines which underlie our adoption of a revised § 399.20 FiT Program price and other program elements. These core policy guidelines were initially set forth as a proposal in the June 27, 2011 ALJ ruling and in the Renewable FiT Staff Proposal.[34] Today, we rely on these guidelines for program implementation and analysis of the various pricing and program design proposals.

Similar to the Renewable Auction Mechanism (RAM) Program, set forth in D.10-12-048, we seek to create a market for small renewable distributed generation that harnesses renewable market forces to set a program price that minimizes costs to ratepayers, prevents overpayment, and stimulates market demand. We also seek to maximize contract value to the ratepayer and utility by using the market to determine the price and to prevent speculative projects from occupying limited program capacity. Also similar to the RAM Program, we seek to create a straightforward program that is easy to administer. Lastly, we seek to limit project development to areas within the existing infrastructure on the

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[34] The foundation of these policy guidelines is found in SB 32, Section 1 (a)-(g), (Legislative Intent).

distribution system and avoid costly, lengthy, and controversial transmission system network upgrades. In summary, these five policy guidelines are as follows:

1. Establish a feed-in tariff price based on quantifiable ratepayer avoided costs that will stimulate market demand;
2. Contain costs and ensure maximum value to the ratepayer and the utility;
3. Ensure administrative ease and lower transaction costs for the buyer, seller, and regulator;
4. Use existing transmission and distribution infrastructure efficiently; and
5. Establish project viability criteria to increase probability of successful projects within the program.

Parties commented upon the proposed policy guidelines set forth in the June 27, 2011 ALJ ruling and the Renewable FiT Staff Proposal and, generally, found these guidelines reasonable. Some parties provided additional input or expressed disapproval. Overall, we find that these guidelines provide an important secondary source of guidance as we implement SB 320, SB 32, and SB 2 1X. Our primary source of guidance, as stated above, is derived from the rules of statutory construction.

For these reasons, below we analyze the various pricing and program design proposals under federal law (avoided costs), state law (statutory interpretation of § 399.20), and these policy guidelines.

4. Price Recommendations by Parties and Staff

In the March 2011 briefs filed in R.08-08-009, July and August 2011 comments, and November 2011 comments on the Renewable FiT Staff Proposal, parties provided proposals for a pricing methodology under § 399.20. Generally, these proposals can be described as being based on the following price

characteristics: (1) the MPR without adders, (2) the MPR with various adders, (3) costs of specific technologies, (4) a net energy metering surplus compensation methodology, (5) California Independent System Operator (CAISO) Gen Hub plus a renewable energy credit (REC) value and adjustment, (6) RAM contracts with a locational adder plus adjustments, and (7) other options. In the discussion that follows, we summarize the proposals.

4.1. Market Price Referent Without Adders

PG&E, SDG&E, The Utility Reform Network (TURN), and California Utility Employees (CUE) support a price based on the MPR, adjusted based on time-of delivery factors, as permitted by the language in § 399.20(d)(2). These parties do not support any adders to the MPR.

While PG&E and SDG&E support reliance on the MPR, they also continue to question the legality of the Commission's adoption of the MPR for the FiT Program under federal avoided cost law and PURPA. They, therefore, support the utilities' voluntary reliance on the MPR, as updated for 2011 in Resolution E-4442. Voluntary reliance is preferred by the utilities because, according to the utilities, mandatory provisions of wholesale service can only be required by the Commission when the Commission authorizes the utilities to offer such mandatory wholesale service at avoided cost, as defined under federal law. Because the utilities do not view the Commission's MPR as an avoided cost for renewables under federal law, the utilities suggest that, if the Commission only allows utilities to voluntarily offer the § 399.20 FiT Program price at the MPR, legal disputes initiated by the utilities could be potentially avoided.

In further support of the continued reliance on the MPR, PG&E, SDG&E, TURN, and CUE point to the following: (1) continued reliance on the MPR is transparent since the MPR calculation has been repeatedly vetted, and (2) the

MPR is a familiar standard within the industry and, accordingly, continued reliance on the MPR will promote administrative ease and market stability.

4.2. Market Price Referent with Solar Photovoltaic Adder

California Solar Energy Industries Association (CALSEIA) supports reliance on the MPR adjusted for time-of-delivery factors and a "solar PV" adder. CALSEIA suggests that solar photovoltaic (PV) systems provide significant value to ratepayers above and beyond the threshold costs of the natural gas-fired proxy plant quantified in the MPR. According to CALSEIA, these additional value components include avoided transmission and distribution costs, the value of increased reliability, blackout avoidance and power quality, avoided air emission associated with natural gas combustion and the associated general societal health benefits.

4.3. Market Price Referent with Forest Biomass Adder

Placer County Air Pollution Control District (Placer County) supports using the MPR adjusted for time-of-delivery factors plus an adder for small forest biomass generation projects on the basis that small forest biomass projects sited in medium and high-risk fire hazard areas could provide significant value by (1) mitigating fire suppression costs; (2) reducing fire settlement awards; (3) reducing health costs from forest fire emissions; (4) protecting utility transmission and distribution assets from fire damage; and (5) protecting the water supply and personal property from fire-related damages.

Placer County's specific proposal consists of a $0.055 per kWh "Wildfire Hazard Reduction Adder" and a 50 MW carve-out for small forest biomass. The adder includes the five-year average (2006-2010) annual cumulative cost to the California Department of Forestry and Fire Protection, the U.S. Forest Service,

and the U.S. Bureau of Land Management for statewide wildfire suppression of $1.201 billion. Placer County states that not all the adder costs are paid by ratepayers of the utilities but instead are paid by federal and state taxpayers generally, which consists of a larger segment of the population than the utilities' ratepayers. Placer County calculates the ratepayer share of the total taxpayer amount is $900,782,000.

Placer County's analysis also relies on a recent study by the U.S. Forest Service and sponsored by the California Energy Commission (CEC),[35] finding that strategic placement of small forest biomass facilities across Northern California could reduce the number of acres burned by wildfire in California by 23.5% per decade, or approximately 2.3% annually.

4.4. Market Price Referent with Environmental and Locational Adders

Silverado Power LLC (Silverado Power), the Solar Alliance, and Vote Solar Initiative generally support using the MPR, adjusted for time-of-delivery factors, as the base price but also suggest a locational adder based on avoided costs for distribution losses, transmission losses, congestion, and transmission and distribution investments. They suggest that § 399.20(d)(1) ("the payment …shall include current and anticipated environmental compliance costs for facilities in local air pollution control or management districts") could require an environmental pricing component but state that no further environmental adjustments are warranted because the MPR already includes an environmental

[35] USDA Forest Service, Pacific Southwest Research Station. 2009. *Biomass to Energy: Forest Management for Wildfire Reduction, Energy Production, and Other Benefits.* California Energy Commission, Public Interest Energy Research (PIER) Program, CEC-500-2009-080.

component. In response to this proposal, TURN points out that the Commission modified the 2009 MPR model to include an escalating annual cost of carbon dioxide (CO2) and other environmental inputs that capture costs related to nitrogen oxides (NOx), sulfur oxides (SOx), particulate matter (PM10), and volatile organic compounds (VOC).[36]

Clean Coalition also supports continued reliance on the MPR adjusted to reflect time-of-delivery payments per § 399.20(d)(3), all current and anticipated environmental compliance costs per § 399.20(d)(1), and locational benefits per § 399.20(e). Regarding environmental benefits, Clean Coalition acknowledges that the MPR currently captures some environmental costs but suggests that under § 399.20(d)(1) the Commission has authority to make further adjustments. Specifically, Clean Coalition recommends that the MPR be adjusted to capture current or future additional environmental compliance costs, including those costs noted by a report cited in CALSEIA's comments[37] on the value to ratepayers of avoided methane, NOx, CO2, SOx, VOCs, and PM10 emissions. Clean Coalition suggests this value could be represented by the addition of 1 cent/kWh to the MPR. Regarding locational benefits, Clean Coalition suggests this value could be represented by the addition of 35% of the MPR based on the type of grid support provided, such as avoided transmission, avoided line losses, reliability and blackout prevention, and improved power quality.

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[36] *See* Resolution E-4298 (issued December 18, 2009). This resolution formally adopted the 2009 MPR values for use in the 2009 RPS solicitations.

[37] http://calseia.org/wp-content/uploads/2010/05/pv-above-mpr-methodology-final-20100423.pdf.

4.5. Technology-Specific Pricing

In the March 2011 briefs and comments filed in July, August, and November 2011, parties, including CEERT, Agricultural Energy Consumers Association and the Inland Empire Utilities Agency, California Wastewater Climate Change Group (CWCCG), Sustainable Conservation, Green Power Institute (GPI), FuelCell Energy, Renewables 100, Sierra Club California (Sierra Club), and Solar Alliance, recommend unique prices for different types of renewable resources.

CEERT supports a § 399.20 FiT Program price that reflects the resource and technology used to generate electricity, as well as the locational attributes of the generation site.[38] CEERT finds that, under existing federal and state law, it is possible for each generation project under the § 399.20 FiT Program to be given a different market price of electricity because according to CEERT, avoided cost can be defined under the law as specific to each resource, technology, and location. CEERT does not, however, recommend that pricing be developed for each individual project. Rather, CEERT recommends that the market price of electricity under § 399.20(d)(1) be differentiated according to resource types, with an avoided cost price determination that reflects the cost of the resource, including the environmental, locational, and supply characteristics of each resource. In this manner, CEERT suggests that the applicable avoided cost price can be tailored to the market segment targeted in § 399.20, which includes projects uniquely situated closer to load centers and sized to interconnect at the distribution level. CEERT claims this approach is appropriate because such

[38] CEERT July 21, 2011 comments at 2.

projects have not been effectively incorporated into any other RPS procurement mechanism.

Sustainable Conservation and GPI also suggest that the Commission adopt technology-specific pricing based on the costs of each technology. According to Sustainable Conservation and GPI, the "market price of electricity" in § 399.20 is an imprecise term and the Commission has significant latitude to set tariff prices. Sustainable Conservation and GPI further suggest that their cost-based pricing proposal be differentiated based on more than just the three electricity product types (baseload, peaking, and as-available) listed in the statute because some generators provide services to the utilities beyond those three types. For example, these parties point out that lagoon systems for dairy farms can be equipped with gas storage at low cost, which allows operations that are not just simple baseload, as is typical for biogas generators, but baseload with the capability of providing load-following services if the appropriate incentives are included in the contract. For these reasons, Sustainable Conservation and GPI support cost-based pricing as a means to diversify California's renewable energy portfolio to include a greater share of biomass, biogas, and other gasification technologies.

While supporting cost-based pricing, Sustainable Conservation and GPI also recognize that data on the costs of these resources is minimal because these industries are largely in the early commercialization phase. To support their

position, they suggest two sources of publicly available price data: (1) a CEC-funded study[39] and (2) a State Water Resources Control Board study.[40]

CWCCG suggests that technology-specific pricing is critical to appropriately provide an incentive for renewable generation at water and wastewater facilities. CWCCG claims that many wastewater agencies already generate some or all of their electrical power, much of this using biogas, but without a technology specific cost-based price that is higher than the current and past MPRs, water and wastewater facilities lack a financial incentive to sell electricity to the utilities.

FuelCell Energy acknowledges that, under the existing legal framework, "there is more than one way the Commission can calculate a price"[41] for the § 399.20 FiT Program. FuelCell Energy supports technology-specific pricing that reflects the value of stationary fuel cells using renewable fuels. FuelCell Energy points to several sources of data for the Commission to calculate a technology-specific price for stationary fuel cells: a study by the University of California and the record of the Commission's proceeding in Application (A.) 09-02-013 and A.09-04-018.[42] FuelCell Energy explains that this data

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[39] Cheremisinoff, Nicholas, Kathryn George, and Joseph Cohen, 2009. *Economic Study of Bioenergy Production From Digesters at California Dairies.* California Energy Commission, PIER Program. CEC-500-2009-058.

[40] California Regional Water Quality Control Board, Central Valley Region, *Economic Feasibility Of Dairy Manure Digester And Co-Digester Facilities In The Central Valley Of California, May 2011.*

[41] FuelCell Energy March 7, 2011 brief at 15.

[42] FuelCell Energy cites to a 2008 study issued by the National Fuel Cell Research Center at the University of California-Irvine, *Build-Up of Distributed Fuel Cell Value In California: Background and Methodology.*

quantifies the incremental value of fuel cell-specific attributes over and above the MPR. These values include avoided capital, operation and maintenance, fuel costs, water use, transmission and distribution, inputs for use of digester gas, cogeneration applications, and general societal benefits provided by fuel cells, including job creation and ease and speed of deployment.

4.6. Net Surplus Compensation Rate

The Division of Ratepayer Advocates (DRA) suggests that the pricing for the § 399.20 FiT Program be derived from the net energy metering net surplus compensation rate. DRA points out that the net surplus compensation rate is an established tariff based on market prices adjusted for renewable attributes. The Commission adopted the net surplus compensation rate in D.11-06-016 to apply to the excess generation from net-energy metered customers. Specifically, the net surplus compensation rate is derived from an hourly day-ahead electricity market price known as the "default load aggregation point" (DLAP) price. In 2009, this average DLAP price for PG&E was approximately four cents per kWh. Net surplus generators may also be compensated at the net surplus compensation rate plus an adder for their renewable attributes based on an interim proxy rate derived from the Western Electricity Coordinating Council average renewable energy premium, published by the Department of Energy. DRA suggests that such a rate could provide price stability to future FiT participants and creates transparency because the price is based on publicly available information.

4.7. CAISO Gen Hub plus REC Pricing with Adjustment Mechanism

SCE supports a market-based pricing approach on the basis that it would enable the Commission to price the program outside of the restrictions imposed

by PURPA and avoided cost limitations. SCE claims that its market-based proposal has many benefits. According to SCE, its proposal avoids the need for a time-consuming and contentious examination of avoided cost. In addition to a Gen Hub base price, it also includes a market-based pricing adjustment mechanism where the price adjusts based on market response. Thus, unlike the administratively-determined prices, such as the MPR, the price will not remain static, at a point potentially too high or too low. Instead, the price could move higher or lower in response to supply and demand of renewable energy in the market. According to SCE, in contrast to a static price, this more flexible proposal offers potential benefits to ratepayers because ratepayers will not have to pay excessive costs for renewable energy if the market price drops. Similarly, sellers would potentially benefit by being able to accept a contract at a price sufficient to develop their projects.

As set forth in its August and November 2011 comments, the main points of SCE's proposal are as follows:

(1) SCE would publish an initial FiT price the first day of each month;

(2) The initial FiT price would be based on an average of the historical one-year day-ahead South Path-15 EZ Gen Hub price published by the CAISO plus the Department of Energy established price for renewable attributes in the Western United States;

(3) A portion of the overall program capacity will be allocated for procurement each month.

(4) The FiT price would increase at an escalating rate each consecutive month in which there is no program subscription (e.g., \$2/MWh, then \$4/MWh, then \$6/MWh, etc.)[43]

(5) The FiT price would decrease at an escalating rate each consecutive month in which there is full subscription (e.g., \$2/MWh, then \$4/MWh, then \$6/MWh, etc.)

(6) If there is partial subscription in any given month, the FiT price would stay the same for the next month.

(7) Any program capacity not subscribed in a month would roll over into the next month.

4.8. RAM Pricing with Locational Adder and Adjustment Mechanism

In their July and August comments, Interstate Renewable Energy Council (IREC), Silverado Power, Vote Solar Initiative, and SunEdison LLC (SunEdison) suggest the Commission set a revised FiT price based on the results of the RAM auction adjusted for time-of-delivery factors. In the Renewable FiT Staff Proposal, the Commission's Staff endorsed this proposal and offered expanded details on how to implement it. The following pricing methodology was presented by Staff:

Base Price Calculation:

(1) Use the results of the RAM auction (with the first RAM auction closing November 15, 2011) to set the price for the § 399.20 FiT Program.[44] At the time the Commission's Staff issued its proposal, the first RAM auction had not yet closed. The first

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[43] SCE changed this aspect of its proposal in its November 2011 comments from its initial presentation in its August 2011 comments.

[44] At the time the Commission's Staff issued its proposal, the first RAM auction had not yet closed. The first auction has since closed. The individual bid prices are confidential.

auction has since closed. The individual bid prices are confidential.

(2) Set a price for three product types: baseload, peaking as-available, non-peaking as-available.

(3) Use the RAM market clearing price from each product type, which will be the highest RAM executed contract price.

(4) Add to the price the project's share of the transmission costs for the particular RAM contract. If the generator triggers transmission costs, then the generator should not receive any payment for avoided transmission.

(5) Adjust price for time-of-delivery factors to capture the value of the product to ratepayers.

Price Adder and Adjustments:

The Renewable FiT Staff Proposal also recommends a locational adder for generation located in so-called "hot spots." Hot spots are defined in the Staff Proposal as "areas where distribution and transmission system upgrades can be deferred if new generation is located in that area."[45] Lastly, the Staff Proposal recommends a price adjustment mechanism for each product type for each utility after a certain subscription level (or lack thereof). Staff did not recommend a particular adjustment mechanism but rather referred to CALSEIA, SCE, Clean Coalition, and Vote Solar Initiative's recommendations.

5. Analysis of Party and Staff Price Recommendations

5.1. Market Price Referent without Adders

PG&E, SDG&E, TURN, and CUE support establishing a market price using the MPR adjusted for time-of-delivery factors. This has been the § 399.20 FiT Program's pricing methodology since the program's inception in 2007. A

[45] Renewable FiT Staff Proposal at 7 (attached to ALJ Ruling dated October 13, 2011).

pricing methodology based on the MPR is an established tested methodology and would be familiar to the renewable energy industry. An MPR-based methodology would offer a high degree of transparency since market participants are well acquainted with the costs embedded within the MPR, such as certain environmental costs. DRA, however, finds the MPR sets an "unrealistically low/unachievable price point" for certain technologies and will fail to support the success of the § 399.20 FiT Program.

We agree with DRA in part. The MPR price may be too high or too low for different FiT product types. We also find using the MPR to set § 399.20 FiT Program price fails to achieve our first policy guideline: to "establish a feed-in tariff price based on quantifiable utility avoided costs that will stimulate market demand." The MPR is a price based on a natural gas-fired electric plant, and not a renewable generator. Instead, it reflects the costs of a different energy market, fossil fuels. Specifically, the MPR does not reflect ongoing changes within the renewable market and, as a result, could potentially result in a price either too low or too high. In addition, the renewable market has evolved since the Commission first established the MPR in 2003 at the beginning of the RPS program. Now the renewable market is sufficiently robust to serve as the point of reference for establishing the market price for small renewable projects rather than the very different market used for the MPR, the combined-cycle natural-gas power plant.

Therefore, because the renewable market is sufficiently robust to serve as a point of reference for the market price for the § 399.20 FiT Program price, we decline to adopt a pricing proposal that relies upon the MPR.

5.2. Market Price Referent with Various Adders

As discussed above, CALSEIA, Placer County, Silverado Power, the Solar Alliance, Vote Solar Initiative, Clean Coalition, and other parties support a pricing proposal based on adjusting the MPR with some type of adder, for example, an adder based on the attributes of a specific technology type, locational conditions, or environmental societal benefits. In the above discussion, we decline to adopt a pricing proposal based on the MPR because, in short, the renewable market is sufficiently robust to more accurately reflect generation costs of the FiT Program as compared to the cost reflected in the MPR, that of a natural gas plant. For this same reason, we decline to adopt the MPR aspect of these proposals.

Regarding the adders recommended by the above parties, we decline to adopt the following adders: solar adder, small forest biomass adder, and environmental adders. We decline to adopt these adders because we do not adopt the MPR as the basis for the § 399.20 FiT Program's price and, as described in more detail at Section 6, below, the basis for the pricing adopted today is the renewable market, which already reflects a value for these adders. In addition, the methodologies for these adders were generally based on avoided societal costs, and not ratepayer or utility costs, which might be argued to be inconsistent with the federal requirement under PURPA.

In addition, these adders were proposed in order to increase the FiT price above the MPR for technologies that may need higher prices. Given the price adjustment mechanism that is adopted in this decision, adders are not necessary. The FiT price should adjust to account for the market price of various resources. If we find that the adjustment mechanism does not reflect the market, including

certain market segments that have additional ratepayer value, the Commission can consider adders in the future.

Furthermore, these adders are inconsistent with three of the policy guidelines: (1) establish a feed-in tariff price based on quantifiable utility avoided costs that will stimulate market demand; (2) contain costs and ensure maximum value to the ratepayer and utility; and (3) ensure administrative ease and lower transaction costs for the buyer, seller, and regulator. As stated above, many of the proposed adders are overly broad societal costs and not costs to utilities or ratepayers. In addition, these adders could increase the contract price above the resource's actual costs and lead to overpayment. As discussed below, market-based pricing calibrates the FiT price to market prices and to market demand, which leads both to reasonable ratepayer costs and prices that can work to stimulate market demand. Last, calculating adders for each technology or specific resource attribute increases the administrative complexity for the program and increases the burden on Commission's Staff to administer the program. For these reasons and the reasons articulated above, we do not adopt the requested adders for the § 399.20 FiT Program.

5.3. Technology-Specific Pricing

The parties advocating technology-specific pricing articulate a key challenge in implementing the § 399.20 FiT Program: establishing an avoided cost pricing methodology consistent with the provisions of state law and federal law that supports specific types of renewable technologies, which provide general societal benefits that cannot easily be quantified. We seek to create a pricing policy that supports a diversity of technologies. In doing so, we must balance a number of competing interests, and find that, at this time, unique

prices for separate technologies is not consistent with state law or the best interest to ratepayers.

Regarding the state law issue, the parties do not address the fact that, as written, state law does not specifically direct the Commission to account for the unique cost of each technology. The plain language of § 399.20 neither directs nor suggests that technology-specific costs be included in a FiT Program price methodology.

Parties refer to § 399.20(d)(1)[46] to support their position on consideration of technology classifications. This subsection is addressed in a separate section in this decision.

Some parties suggested that federal law supports technology-specific prices. While federal law, as discussed above, provides the Commission with the latitude to take into account the state's legislative energy procurement mandates when establishing avoided costs, the state statute, as codified in § 399.20, does not direct the Commission to consider technology-specific costs when determining the § 399.20 FiT Program price.

We also find technology-specific pricing inconsistent with three of our policy guidelines: (1) Establish a feed-in tariff price based on quantifiable utility avoided costs that will stimulate market demand; (2) Contain costs and ensure

[46] This statute refers to certain costs that the Commission must consider in setting a tariff price and provides, in pertinent part, as follows: "The payment…shall include all current and anticipated environmental compliance costs, including, but not limited to, mitigation of emissions of greenhouse gases and air pollution offsets associated with the operation of new generating facilities in the local air pollution control or air quality management district where the electric generation facility is located."

maximum value to the ratepayer and utility; and (3) Ensure administrative ease and lower transaction costs for the buyer, seller, and regulator.

Technology-specific pricing does not establish a § 399.20 FiT Program price based on the renewable market and competitive pressures but rather would use an administratively-determined calculations to establish a price based on the costs plus a fair rate of return to build and operate a specific technology. Ultimately, we find this method of calculating price will weaken the ability for competition to control contract costs.

Next, this method does not ensure the maximum value to the ratepayer and utility. For example, if different technologies within a product type have the same value to the utility but different costs, the utility is going to overpay since the more expensive technologies have the same value as lower priced technologies.

Finally, determining the costs of each renewable technology increases the administrative complexity and the transaction costs for the regulator, who is responsible for calculating each technology's cost for the § 399.20 FiT Program.

Accordingly, we do not adopt technology-specific pricing as it fails to comply with federal and state law and with our policy guidelines for implementing the § 399.20 FiT Program. We do, however, seek to encourage a diversity of technologies through our adopted pricing methodology.

5.4. Net Surplus Compensation Rate

AB 920 amended § 2827 in order to pay net-energy metered customers for their excess generation over a one-year period. D.11-06-016 found that net surplus generation by net-energy metered customers has no capacity value because an individual net-energy metered customer has no obligation to provide energy to the utility. Net surplus generation is provided without a power

purchase agreement on an intermittent, unpredictable, and as-available basis over a 12-month period. In addition, the Commission found that the only generation the utility avoids when a net-energy metered customer provides surplus generation is reduced electricity procurement from the short-term wholesale market.

Since renewable generators under the § 399.20 FiT Program are required to sign long-term power purchase agreements (a minimum of 10 years per § 399.20), generators under the § 399.20 FiT Program represent a different value than the net surplus compensation from net-energy metered customers and, accordingly, should not be paid the same rate. Finally, we find that the net surplus compensation rate violates our first policy guideline, to "establish a feed-in tariff price based on quantifiable utility avoided costs that stimulate market demand," since the rate is based on the hourly day-ahead electricity market price, or DLAP price, and not the market price for renewable electricity.

Accordingly, because the market served by net-energy metered customer is different than the market served by the § 399.20 FiT Program, we do not adopt a pricing methodology based on the net-surplus compensation rate.

5.5. CAISO Gen Hub plus REC with Adjustment Mechanism

We decline to adopt SCE's proposal to use the CAISO Gen Hub plus the REC as the § 399.20 FiT Program starting price for the same reasons we do not adopt the net surplus compensation rate. We find merit, however, in SCE's recommendation to rely on the market to set a starting price for the FiT Program and agree that a price set by the market avoids the need for a time-consuming and contentious examination of costs. A market-set price permits flexibility and responds to market demand. We also find merit in SCE's recommendation to

adjust the § 399.20 FiT Program starting price based on market conditions since this mechanism will allow the starting price to adjust to renewable market prices if it is initially set too high or too low. Therefore, we adopt SCE's adjustment mechanism, in part, as articulated in its August and November 2011 comments.

5.6. RAM Pricing with Locational Adder and Adjustment Mechanism

As more fully discussed in Section 6, below, we adopt the component of the proposals by IREC, Silverado Power, Vote Solar Initiative, SunEdison, and Staff that relies on RAM contracts adjusted for time-of-delivery factors to set the § 399.20 FiT Program starting price. When combined with SCE's adjustment mechanism, using RAM contracts to set the FiT Program starting price is consistent with the three policy guidelines that relate to choosing a FiT price: (1) establish a feed-in tariff price based on quantifiable utility avoided costs that stimulate market demand; (2) contain costs and ensure maximum value to the ratepayer and utility; and (3) ensure administrative ease and lower transaction costs for the buyer, seller, and regulator. Section 6, below, more fully describes the adopted market-based pricing methodology, which is referred to as the Renewable Market Adjusting Tariff (Re-MAT), and includes an analysis of the adopted market-based pricing methodology under federal and state law.

We do not adopt other components of the Renewable FiT Staff Proposal, including the location adder or a transmission adder because we find these components either inconsistent with existing law or require more development. Regarding the transmission adder, we find that the record does not support a determination that the transmission costs for particular RAM contracts constitute the avoided transmission costs for renewable FiT generators under the law. As discussed previously regarding Clean Coalition's suggested location adder, we

agree with the concerns expressed by SCE and the other utilities that additional scrutiny is needed before the Commission adopts a location adder. Furthermore, the requirement that projects in the § 399.20 FiT Program be "strategically located," as discussed separately in Section 6.9, addresses the concerns that parties and Staff sought to address through a locational adder, which is to provide an incentive to generators to locate in areas with load in order to avoid upgrades to the transmission system.

6. Adopted FiT Pricing Methodology – Renewable Market Adjusting Tariff or Re-MAT

Section § 399.20 contains a number of mandatory and discretionary considerations that apply to any pricing methodology adopted by the Commission for the FiT Program. The pricing methodology must also be consistent with federal law on avoided costs for wholesale transactions under PURPA. Today's decision adopts a pricing methodology that relies upon renewable market power pricing information from the RAM adopted in D.10-12-048 and takes components from a number of different pricing proposals presented by parties, including IREC, SunEdison, Silverado Power, Vote Solar Initiative, SCE and Staff. Importantly, we adopt an adjustment mechanism to increase or decrease the FiT price for a particular product type based on market conditions. The pricing methodology we adopt today, Re-MAT, complies with both state and federal law.

6.1. Compliance with Federal Law

In prior decisions, we found that the FiT price was constrained by the statutory cross-reference to § 399.15 within the FiT statute, § 399.20. We further found that, based on this cross-reference to § 399.15, pricing for FiT was limited to the MPR. Today, based on the removal of this cross-reference, we have greater

latitude to consider other pricing options under state law.[47] As discussed above, FERC's recent interpretations in response to a petition for declaratory order also support consideration of additional pricing options, as long as the facilities are QFs and the pricing options are an avoided cost. Therefore, it is reasonable for us to shift the price away from the MPR to the renewable power market. We further find that a FiT price that reflects the renewable market ultimately more fully reflects avoided costs under federal law. Therefore, relying on the existing RAM Program to establish the baseline for pricing is a reasonable starting point to determine avoided cost for the § 399.20 FiT Program.

Because the § 399.20 FiT Program seeks to implement a directive from the Legislature to procure energy from specific sources, renewable generation of 3 MW and less, and to consider the value of different electricity products, including baseload, peaking, and as-available electricity, we find using RAM contracts to set the § 399.20 FiT Program starting price, which includes these product types, is the most reasonable alternative to determining the cost of the resources being avoided.

Our finding is based on the fact that the market segment represented by RAM more closely represents the market segment covered by § 399.20 than other pricing proposals, including pricing proposals relying on the MPR. The discussion above at Section 5 fully addresses this matter.

The market segments covered by RAM and § 399.20, however, are not the same. RAM covers renewable projects sized up to 20 MW. The § 399.20 FiT

[47] *See* Section 3.1, above, for a more detailed discussion of the changes to the statutory language in § 399.20 relevant to the cross-reference.

Program covers renewable projects sized up to 3 MW. Other renewable procurement programs include the RPS Annual Solicitation and bilateral contracting process, which generally result in contracts greater than 20 MW and as large as 1,000 MW, with an average size of about 100 MW. Nevertheless, while not identical, the RAM Program presents the closest comparison and, as such, we find it reasonable to define Re-MAT, which includes the market adjustment mechanism, as an avoided cost, as required under federal law.

6.2. Compliance with State Law

In terms of compliance with state law, we find that our proposal meets the requirements of § 399.20. The Legislature provided specific information that we must consider in setting the § 399.20 FiT Program price but left the Commission with the discretion on how to factor these considerations into any pricing methodology that we ultimately adopt.

Section 399.20(d)(1) provides that the tariff price shall be, among other things, the market price determined by the Commission. Today, the Commission adopts a market price by relying on contracts approved from a specific renewable auction market, specifically the RAM auction set forth in D.10-12-048. In addition, the Re-MAT's adjustment mechanism seeks to account for any differences in pricing from the RAM Program and the § 399.20 FiT Program by increasing or decreasing the price if the initial price is too low or too high. The pricing methodology is also guided by other provisions of § 399.20 that are discussed elsewhere in this decision. These provisions include, for example, that the generation be "strategically located," that the tariff be offered on a "first-come-first-served basis," and that "ratepayers that do not receive service pursuant to the tariff are indifferent to whether a ratepayer with an electrical generation facility receives service pursuant to the tariff."

Specifically, the Re-MAT is in compliance with the following provisions of § 399.20:

Section 399.20(d)(2)(A) provides that the Commission shall establish a price in consideration of long-term market price for fixed price contracts pursuant to an electrical corporation's general procurement activities. The Commission has considered long-term market price for fixed price contracts pursuant to an electrical corporation's general procurement activities because today's adopted methodology, Re-MAT, relies upon RAM contracts as set forth in D.10-12-048, which are part of each electrical corporation's general procurement.

Section 399.20(d)(2)(B) provides that the Commission shall establish a price in consideration of long term ownership, operating and fixed-price fuel costs. The Commission has considered long term ownership, operating and fixed-price fuel costs because Re-MAT relies upon RAM contract prices as set forth in D.10-12-048 which includes such costs.

Section 399.20(d)(2)(C) provides that the Commission shall establish a price in consideration of the value of electricity products, e.g., baseload, peaking, and as-available. The Commission has considered the value of different electricity products because Re-MAT's adopted market-based methodology includes pricing for three product types.

Section 399.20(d)(1) provides that the tariff shall provide for payment of every kilowatt hour of electricity purchased. The Commission has adopted a mechanism that establishes a kWh price and, therefore, is in compliance with this provision.

Section 399.20(d)(1) provides that the tariff shall provide for payment for a period of 10, 15, or 20 years. The adopted price methodology permits contracts of any of these terms.

Section 399.20(d)(1) provides that the tariff shall provide for payment of, among other things, all current and anticipated environmental compliance costs, including, but not limited to, mitigation of emissions of greenhouse gases and air pollution offsets associated with the operation of new generating facilities in the local air pollution control or air quality management district where the electric generation facility is located. Re-MAT theoretically includes, as embedded within the starting price, general costs associated with producing renewable energy. We seek to pay generators the price needed to build and operate a renewable generation facility. We do not find, however, that specific costs, such as compliance costs in a particular air quality management district, are necessarily captured by the RAM methodology. More analysis is needed. We further discuss our proposal for compliance with § 399.20(d)(1) in a separate section.

A more specific discussion of the components of Re-MAT follows.

6.3. Three Product Types and Re-MAT Starting Price

The existing FiT Program based on the MPR does not distinguish among different product types and only offers one price. Section 399.20(d)(2)(C) directs the Commission to consider, and today's decision adopts, a price for each of the following three product types: baseload, peaking as-available, and non-peaking as-available. Our decision reflects an effort to better capture the value provided by different technology types. Baseload projects provide firm energy deliveries (e.g., bioenergy and geothermal); peaking projects provide non-firm energy

deliveries during peak hours (e.g., solar); and non-peaking as-available projects provide non-firm energy deliveries during non-peak hours (e.g., wind and hydro).

For each of the three FiT product types, we adopt a Re-MAT starting price for the § 399.20 FiT Program based on the weighted average of PG&E's, SCE's, and SDG&E's highest executed contract resulting from the RAM auction held in November 2011. While a unique starting price for each product type was considered as an option, we opted otherwise because the November 2011 RAM contract prices contained insufficient market information for the three product types to render this option viable.[48] As a result, we adopt PG&E's recommendation articulated in its November 2011 comments to use a weighted average of the highest executed RAM contract from each investor owned utility (IOU) to establish a single, statewide FiT starting price for each of the three product types. This is a reasonable starting price for the FiT because it is set by the most recent comparable competitive solicitation for renewable distributed generation.

In addition, we find it prudent to adjust this starting price by time-of-delivery factors based on the generator's actual energy delivery profile, since this captures the value of each generator to the utility. Lastly, we find that the price adjustment mechanism, described below, adequately functions to

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[48] The utilities recently filed advice letter seeking Commission approval of the auction results from the first RAM solicitation, PG&E Advice Letter 4020-E (March 20, 2012), SCE Advice Letter 2712-E (March 29, 2012), SDG&E Advice Letter 2343-E (April 3, 2012).

capture the different costs associated with the small renewable distributed generation market segment compared to the RAM market segment.

Based on the results from the November 2011 RAM auction, we anticipate that the starting price for each separate product type will be $89.23/MWh (pre-time-of-delivery adjustment). [49] PG&E, SCE, and SDG&E shall incorporate this starting price, the price adjustment mechanism, and incremental capacity releases, as discussed below, into their tariffs and standard contracts, as appropriate, for the § 399.20 FiT Program.

6.4. Re-MAT Price Adjustment Mechanism For Each Product Type

We also adopt a price adjustment mechanism for the three product types, i.e., baseload, peaking as-available, and non-peaking as-available. A proposal for triggering a price adjustment was included as part of SCE's August 5, 2011 comments,[50] and we adopt SCE's proposal, in part. Under the adopted price adjustment mechanism, the price for a utility's product type may increase or decrease every two months provided certain conditions exist. Each utility will make the FiT prices publicly available on its website by the first business day of the month in which the price adjustment occurs.

A price adjustment mechanism will enable the FiT price to quickly respond to market conditions. It is also designed to prevent gaming by only

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[49] SCE executed contracts from the first RAM auction on February 13, 2012. PG&E executed contracts from the first RAM auction on February 27, 2012. SDG&E executed contracts from the first RAM auction on March 30, 2012. The Commission's Energy Division Staff approved these contracts, effective April 29, 2012 for PG&E, April 30, 2012 for SCE, and May 3, 2012 for SDG&E.

[50] SCE August 5, 2011 comments at proposed tariff "Special Condition #8 MP FiT Pricing and Cumulative Procurement Targets," Appendix A Schedule MP FiT, Sheet 5.

increasing or decreasing provided that a defined level of market interest exists for a product type.[51]

As part of today's decision, interested generators that meet the program's minimum project viability criteria (Section 10) must submit a program participation request form to the utility. Once the participation request form is deemed complete, the utility will establish a queue on a first-come-first-served basis for each product type. Every two months, the utility will offer generators a FiT contract at that two-month Re-MAT price in order of the Re-MAT queue. A generator can accept or reject the price. If a generator accepts the price, it enters into a FiT contract. The price is fixed for the term of contract. If the generator declines a contract at that price, it maintains its position in the queue until the next two-month period.

The price adjustment will be triggered only after least five eligible projects by different developers are in the queue. If there are less than five projects by different developers for any two-month offering, then the Re-MAT price remains the same for the next two-months. If at least five eligible projects by different developers are in the queue, the price may increase or decrease based on whether projects accept the Re-MAT price and a certain subscription level is met. If no developer enters into a FiT contract at the two-month price, then a price increase will be triggered for the following two-month period. Or, if the threshold of five eligible projects with different sponsors is achieved and the all available capacity

[51] For example, a price adjustment mechanism should not create an incentive for generators to purposefully withhold executing a contract in order to force a price increase.

is subscribed for in a product type, a price decrease is triggered for the following two-month period.

The manner in which the mechanism will function to increase or decrease the price is described below.

6.4.1. Increased Price - Illustrated

As stated above, if there are five projects with different developers in the queue for a particular project type and if certain conditions exist, the Re-MAT price will adjust in the subsequent two-month period. The condition for a price increase is either (1) if no projects subscribe or (2) if program subscription for a two-month period is less than 50% of the initial starting capacity for that project type. There must also be at least five eligible projects from different sponsors in a utility's queue for a product type. The price will increase for each consecutive two-month period until there is subscription capacity equal to 50% or more of the initial starting capacity for that product type. At that point, the price remains the same until the criteria for a price decrease are met. The following serves to illustrate how this mechanism works to increase the price:

- Months 1-2: Starting Price ($89.23/MWh). If no subscriptions result or less than 50%, then the price increases as follows:
- Months 3-4: Starting Price + $4.00/MWh (total $4.00/MWh increase over prior period) and, if no subscription results or less than 50%, the price increases as follows:
- Months 5-6: Starting Price+ $12.00 (total of $8.00 increase over prior period) and, if no subscription results or less than 50%, the price increases as follows:
- Months 7-8: Starting Price + $24.00 (total of $12.00 increase over prior period) and, if no subscription results or less than 50%, the price increases as follows:

- Months 9-10: Starting Price + $40.00 (total of $16.00 increase over prior period) and, if no subscription results or less than 50%, the price increases as follows:
- Months 11-12: Starting Price + $60.00 (total of $20.00 increase over prior period).

Any program capacity not subscribed in a two-month period will be distributed as described in Section 6.5.

It is our expectation that more expensive technologies such as biogas and forest biomass, may gain the opportunity to participate in the FiT Program by, for example, Months 9-10, after the price has increased by $40/MWh to $129.23, assuming no subscriptions in the product type have occurred before that date and a minimum of five project sponsors exist in the Re-MAT queue. Additional time may be required to reach that price if less expensive technologies subscribe to the product type.

To guard against ratepayer exposure to excessive costs due to market manipulation or market malfunction, PG&E, SCE, and SDG&E shall file a motion to temporarily suspend all part of program when evidence of market manipulation exists. The motion will be acted upon expeditiously. The motion shall identify the portion of the program suspended, the specific behavior and reasons for the suspension, and the utility's proposal for resolving the program. The motion shall be served on the service list of this proceeding or any successor proceeding. The utilities must rely upon this motion in a manner that minimizes disruption of the program. For example, if a utility identifies market manipulation or malfunction in one product type or by one project sponsor, the motion requesting the suspension should be limited accordingly. In this manner, the suspension will balance the need to protect ratepayers from excessive costs without unreasonably hindering the functioning of the program.

6.4.2. Decreased Price - Illustrated

As previously discussed, if there are five projects with different developers in the queue for a particular project type and if certain conditions exist, the Re-MAT price will adjust in the subsequent two-month period. The condition for a price decrease is if subscription in a two-month period equals 100% or more of the initial capacity allocation for that produce type, regardless of the total available capacity for that product type for the two-month period. The price will stay the same if subscription in the two-month period is less than 100% of the initial capacity allocation for that product type. The following serves to illustrate how this mechanism works to decrease the price:

- Months 1-2: Starting Price ($89.23/MWh). If subscription equals 100% or more of the initial capacity allocation for that product type, then the price decreases as follows:
- Months 3-4: Starting Price minus $4.00 (total $4.00 decrease from prior period) and, if subscription equals 100% or more of the initial capacity allocation for that product type , the price decreases as follows:
- Months 5-6: Starting Price minus $12.00 (total of $8.00 decrease from prior period) and, if subscription equals 100% or more of the initial capacity allocation for that product type, the price decreases as follows:
- Months 7-8: Starting Price minus $24.00 (total of $12.00 decrease from prior period) and, if subscription equals 100% or more of the initial capacity allocation for that product type, the price decreases as follows:
- Months 9-10: Starting Price minus $40.00 (total of $16.00 decrease from prior period) and, if subscription equals 100% or more of the initial capacity allocation for that product type, the price decreases as follows:
- Months 11-12: Starting Price minus $60.00 (total of $20.00 decrease from prior period).

6.5. Assignment of Capacity to Three Products Incremental Release of Capacity and Three-MW Minimum to Start

In addition to allocating the program capacity among the three utilities, as discussed in Section 12.3, we direct utilities to assign an equal portion of this allocated capacity to three product types over 24 months, i.e., baseload, peaking as-available, and non-peaking as-available. Any remaining unsubscribed capacity at the end of a two-month period is reallocated to the end of the 24 months, starting with a new period, Months 25-26. The MW should be spread out among Months 25-26 and further in a manner that reflects the initial allocations across Months 1-24. We adopt this design in an effort to stimulate the market for small renewable distributed generation by providing an adequate supply of available capacity to each product type in response to demand.[52]

To implement this directive, each utility must divide the total program capacity by 24 and then assign one-third into each product type.

In Months 1-2, we require that each utility allocate a minimum of 3 MW to each product type.[53] The same minimum obligation would apply to Months 25-26, if applicable.

Each utility is directed to publicly notice the amount of capacity remaining in each product type on its website by the first business day of each two-month period.

This overall plan to allow IOUs to propose reallocation of capacity over 24 months (or perhaps further) is designed to minimize ratepayer exposure to a

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[52] SCE, CEERT, CALSEIA, and FuelCell Energy suggest a similar approach.

[53] The 3 MW should be subtracted from the total amount of MW prior to allocation of equally among product types.

large number of non-competitively priced contracts while ensuring that some capacity is available for each product type, for which there is market interest.

6.6. Program Forums and Future Modifications to the Adjustment Mechanism

Since the adjustment mechanism adopted today is a new feature for the FiT Program, the utilities shall convene stakeholders within the first year of the program to solicit market experience with the price adjustment mechanism. Utilities shall also set up an on-line feedback mechanism with, for example, public questions and answers posted on the web.[54] In such a manner, utilities can gain continuous input to improve their programs. The utilities and market participants should address specific elements of the adjustment mechanism, such as the adjustment time period (e.g., two-months versus one-month or four months), the amount of the periodic price increase or decrease, and any other implementation aspect of the adjustment mechanism. To the extent that changes to the adjustment mechanism or other aspects of the program are needed to improve the program, the utilities may file a joint advice letter with the Commission seeking specific changes to the mechanism. Alternatively, Commission Staff may propose modifications to the adjustment mechanism through a draft resolution for consideration by the Commission.

6.7. Environmental Compliance Costs

Section 399.20(d)(1) refers to environmental compliance costs that the Commission must consider in setting a FiT tariff price and provides, in pertinent part, that: "The payment . . . shall include all current and anticipated environmental compliance costs, including, but not limited to, mitigation of

[54] SDG&E April 9, 2012 comments to proposed decision at 11.

emissions of greenhouse gases and air pollution offsets associated with the operation of new generating facilities in the local air pollution control or air quality management district where the electric generation facility is located."[55]

The costs referred to in this subsection are specifically described as "compliance costs." We view these compliance costs as distinct from general environmental societal values associated with particular forms of generation, including biogas and biomass. In some instances, parties relied on § 399.20(d)(1) to support their position that the Commission adopt an environmental adder or, in some other manner, incorporate into the FiT price a component to reflect specific environmental benefits of different generation technologies. For example, parties representing the biogas industry, including CEERT, AECA, Sustainable Conservation and others discussed the value of the reduction in emission of methane. Similarly, parties, including Placer County and others, representing the forest biomass industry explained the value of reduced air emissions from wildfires, mitigated fire suppression costs, and public safety benefits.

We support these renewable generation industries and their potential to contribute to the reduction of greenhouse gas emissions and improve air quality. In addition, we are impressed with the potential for the forest biomass industry to improve public safety through the reduction of wildfires.

Today, however, our focus is on implementing the legislative mandates of SB 32 and SB 2 1X, which direct us to incorporate into rates, among other factors,

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[55] § 399.20(d)(1).

environmental compliance costs. The legislation does not address the cost savings related to general environmental benefits or increased public safety.

We make this decision with some reluctance as we understand that a price adder is needed, in some instances, to more closely reflect the costs of certain emerging industries. Furthermore, we have heard from parties that, in the absence of such an adder, the growth of these emerging technologies may be hindered.

However, we expect the price adjustment mechanism to account for varied resource costs within a produce type and will monitor the program to ensure its success. In addition, we continue to be concerned about cost containment, generally, and in light of SB 2 1X have been closely reviewing cost containment in the context of overall renewable procurement in other aspects of this proceeding.

For this reason, at this point in time, we look toward the ratepayer indifference requirement in § 399.20(d)(3) and our goals of cost containment within the RPS Program for guidance on the extent to which the Commission should adopt a general environmental adder and find that, at this time, the ratepayer indifference clause of the statute and the directives on cost containment require us to refrain from general environmental adders even in those instances, such as biogas and forest biomass, where the environment and public safety qualities of the renewable generation technology is promising.

It is our intent, however, to encourage the growth of these technologies through the pricing mechanism we adopt today. The pricing mechanism is designed to respond to the market signals for different product types, including baseload. Biogas and forest biomass, presumably, will successfully bid into

baseload in a manner that will further inform this Commission of the pricing requirements of those industries.

Turning now to the specific legislative directive in of § 399.20(d)(1) and an adder to reflect the cost of environmental compliance, a few parties submitted evidence on this topic. We find that specific costs, such as the compliance costs in a particular air quality management district, are not necessarily by the RAM pricing methodology. We remain open to adopting specific adders, such as those discussed by the County Sanitation District of Los Angeles County, to reflect compliance costs.[56]

Similar data was presented by FuelCell Energy.[57] Other parties claim they submitted relevant data but we found much of this data to reflect general environmental costs and not, as specified by the statute, the cost of environmental compliance.

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[56] County Sanitation District April 9, 2012 comments on proposed decision at 9 (presenting data on the compliance costs specific to the South Coast Air Quality Management District and estimating that for the County's 5.4 MW engine facility will require approximately $9.8 million in system upgrades and $.5 million in annual operations costs to comply with a recent proposal by the Air Quality Management District).

[57] FuelCell Energy April 9, 2012 comments on proposed decision at 5-6, citing to March 7, 2011 brief (presents data by incorporating by web link to a UC-Irvine fuel cell study entitled *Build-Up of Distributed Fuel Cell Value in California: Background and Methodology*. This study is available at http://www.nfcrc.uci.edu/2/FUEL_CELL_INFORMATION/MonetaryValueOfFuelCells/PEMFuelCellValue_May2008.pdf and includes statewide data on avoided environmental costs, noting the specific values associated with air quality management districts. FuelCell Energy suggests that the Commission rely on this data, specifically the midpoint of the trading ranges for each pollutant over the prior 12 month period could be averaged from different sources and used to set the multiplier for each district to reflect costs associated with compliance in an air quality management district.

We are mindful of the importance of quantifying this cost and find it essential for the Commission's compliance with the statute. More analysis and data is required, however, to complete this task. We will prioritize this issue in this proceeding and will resolve this matter. Today, however, we find that insufficient evidence exists in the record to adopt and implement an adder reflecting the cost of environmental compliance under § 399.20(d)(1).

6.8. Resource Adequacy

Section 399.20(i) states "the physical generating capacity of an electric generation facility shall count toward the electrical corporation's resource adequacy requirement for purposes of Section 380."[58] Parties presented a range of proposals on how to implement this provision.

The utilities stated that to count a generator for resource adequacy, the CAISO must deem the generator deliverable but, for this to occur, the CAISO must complete a deliverability study, which takes almost two years to complete and could result in costly system upgrades.[59] Notably, at this time, generators interconnecting through the presently effective Tariff Rule 21 do not have the option to apply for a deliverability study.[60]

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[58] Section 380 provides, in part, that the Commission, in consultation with the CAISO, shall establish resource adequacy requirements for all load-serving entities.

[59] The CAISO, not the Commission, determines whether a project obtains resource adequacy.

[60] Pursuant to the revisions to Rule 21 proposed by the settling parties in R.11-09-011, the tariff would remain an energy-only tariff and would expressly state that an interconnection applicant under Rule 21 (revised) is not prohibited from applying for an assessment under the utility's applicable wholesale distribution access tariff. (*See Motion for Approval of Settlement Agreement Revising Distribution Level Interconnection Rules and Regulations*, Proposed Revised Rule 21 at Section E.2.b.iii.

Based on the view that a deliverability study is overly burdensome from a time and cost perspective for very small generators, most parties and the Commission's Staff recommended rejecting the utilities' proposal. Specifically, in order to be studied for deliverability, a generator must request deliverability from the CAISO when it seeks interconnection. The CAISO only performs deliverability studies once a year and a generator must apply by March 31 in order to be studied that year. The deliverability study consists of two phases and application fees and deposits to stay in the study process. The total study process can take two years and the study may require costly upgrades to the transmission system in order to make the generator fully deliverable. Because these requirements are burdensome for small generators, on May 16, 2012, the CAISO Board of Governors approved the Resource Adequacy Deliverability for Distributed Generation initiative, which will provide an alternative path to deliverability for distributed generation.[61] Those changes will not apply until the 2013-2014 Resource Adequacy year and the success of the revisions will not be known until much later.

In November 2011 comments, PG&E proposed a solution to address, in the near term, the concerns related to requiring a deliverability study but, at the same time, ensure compliance with § 399.20(i). PG&E recommends the Commission establish time-of-delivery factors for generators that do not provide

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[61] California Independent System Operator, *Resource Adequacy Deliverability for Distributed Generation Draft Final Proposal* (March 29, 2012) (available at: http://www.caiso.com/Documents/DraftFinalProposal-Deliverability-DistributedGeneration.pdf). The Commission Staff collaborated with the CAISO in developing this proposal and fully supported the proposal before the CAISO Board of Governors.

resource adequacy. We find PG&E's proposal reasonable since it allows generators to choose to pursue a deliverability study if they want to receive a higher time-of-delivery adjusted price. It also removes the burden of pursuing deliverability if the costs and timing are too burdensome.

Moreover, since the deliverability study process can occur over a long period of time, generators can convert to full deliverability after their online date and receive the higher time-of-delivery factors at that time. As a result, full commercial deliverability status should not be a condition precedent for any generator seeking a contract under the § 399.20 FiT Program.

Accordingly, PG&E, SCE, and SDG&E shall offer two sets of time-of-delivery factors: one for generators that do not provide resource adequacy and another for generators that do provide resource adequacy. PG&E, SCE, and SDG&E shall add a provision reflecting delivery factors to the FiT Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision submitted by the utilities and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

6.9. Define "Strategically Located"

Today's decision implements the requirement that generators participating in the § 399.20 FiT Program be "strategically located."

Section 399.20(b) contains four specific criteria that an electric generation facility must meet to sell electricity under the § 399.20 FiT Program. The third criterion is that the generation facility be "strategically located." The concept set forth in this provision is different than the concept in subsection (e) of § 399.20, which describes the value of a project's electricity as potentially influenced by its

location on the distribution network.[62] In contrast, the specific statutory provision in subsection (b) is a prerequisite to participation in the program and provides as follows: The electric generation facility is "strategically located and interconnected to the electrical transmission and distribution grid in a manner that optimizes the deliverability of electricity generated at the facility to load centers."[63]

This provision, in its current format, was first incorporated into § 399.20 by SB 380 but existed, in a more limited manner, in the original legislation, AB 1969.[64] On August 5, 2011, SCE commented on the meaning of this statutory provision. Specifically, SCE suggested that the generator interconnect at one of the preferred locations as identified on SCE's circuit map posted on its website. The Renewable FiT Staff Proposal offered an alternative to SCE's suggestion. Specifically, the Commission's Staff suggested that generators be interconnected to the distribution system and not exceed the minimum load of the circuit when generating electricity. Both of these recommendations intend to target generators as eligible for the program that do not have impacts on the transmission system.

[62] Subsection (e) of § 399.20 states, in pertinent part: "The commission shall consider and may establish a value for an electric generation facility located on a distribution circuit that generates electricity at a time and in a manner so as to offset the peak demand on the distribution circuit."

[63] § 399.20(b)(3).

[64] AB 1969 enacted § 399.20(f) which stated: "Public water and wastewater facilities are strategically located and interconnected to the electric transmission systems in a manner that optimizes the deliverability of electricity generated at those facilities to load centers."

We find that the statutory language means that a generator must be interconnected to the distribution system, as opposed to the transmission system, and must be sited near load, meaning sited in an area where interconnection of the proposed generation to the distribution system requires $300,000 or less of upgrades to the transmission system.

In making this determination, we rely on our policy guideline to use existing transmission and distribution infrastructure efficiently. We further point out that our policy guideline is grounded in the legislation intent set forth in SB 32 (Sec. 1) which emphasizes the importance of encouraging the location of clean generation close to load centers in order to meet increases in demand for electricity.

To implement our interpretation of subsection (b)(3), we find that if a project's most recent interconnection study shows that the project requires more than $300,000 of transmission system network upgrades, that project is no longer eligible for the § 399.20 FiT Program[65] As described in Section 10, below, one project viability criteria is that a project must have completed its system impact study or cluster study phase 1 study (the first of two interconnection studies). Therefore, the generator will have information on whether a project qualifies as "strategically located" before signing a power purchase agreement. We expect generators to use the utilities' Interconnection Maps, available to the public and

[65] This figure is based on the highest per MW costs of the levelized median total upgrade costs of solar PV projects up to 3 MW from the Renewables Portfolio Standard Quarterly Report. Third Quarter 2011 at 10-11. This report can be found at: http://www.cpuc.ca.gov/NR/rdonlyres/2A2D457A-CD21-46B3-A2D7-757A36CA20B3/0/Q3RPSReporttotheLegislatureFINAL.pdf.

online, to locate sites that have a low likelihood of transmission impacts. Furthermore, we find that this prerequisite, "strategically located," applies to all generators seeking a contract under the § 399.20 FiT Program.

Accordingly, PG&E, SCE, and SDG&E shall add to the § 399.20 FiT Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling the prerequisite that generators must be "strategically located." This means that the generator be (1) interconnected to the distribution system, as opposed to the transmission system, and (2) sited near load, meaning in an area where interconnection of the proposed generation to the distribution system requires $300,000 or less of upgrades to the transmission system. Such a provision shall be presented to the Commission for consideration in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision submitted by the utilities and in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

6.10. Ratepayer Indifference

In March 2011 briefs and comments filed in July, August, and November 2011, parties addressed the meaning of the requirement under § 399.20 that "ratepayers that do not receive service pursuant to the tariff are indifferent to whether a ratepayer with an electric generation facility receives service pursuant to the tariff."[66] Some parties, including CEERT, stated that ratepayers are indifferent to any avoided cost rate. Other parties found ratepayers to be

[66] § 399.20(d)(3).

indifferent to any rate that is value based. These parties include CALSEIA, Agricultural Energy Consumers Association (AECA)/Inland Empire Utilities Agency, and Clean Coalition. Clean Coalition also cited the Commission's application of a customer indifference provision in the implementation of AB 1613.[67] Other parties, such as SCE, suggest that a market-based pricing methodology, which adjusts to reflect changes in the market, will ensure ratepayer indifference by establishing a price based on the market, thereby containing costs and ensuring maximum value to the customer and utility.

Notably, in D.10-12-048, we favored market-based pricing as a means of protecting ratepayers, stating that: "Administrative determination of contract prices is less likely to be as responsive to cost changes than is a seller determining the price it wishes to seek in an auction based on its understanding of the underlying project costs, and changes in those costs."[68] Similarly, we find today that Re-MAT, a market-based pricing methodology, best ensures ratepayer indifference under § 399.20(d)(3). A market-based approach is in the best interest of California electricity customers. We now know that the state's renewable energy market has matured and prices have decreased.[69]

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[67] "In light of these considerations, we find that customer indifference under AB 1613 would not be achieved if the price paid under the program only reflected the market price of power. As discussed, since customers who are not utilizing the eligible Combined Heat and Power system will receive environmental and locational benefits from these systems, the price paid for power should also include the costs to obtain these benefits." (D.09-12-042 at 17.)

[68] D.10-12-048 at 16-17.

[69] *See, e.g.*, DRA June 21, 2011 comments (noting that recent changes in the California renewable energy market make it reasonable to transition from basing the Section 399.20 tariff price on the MPR to a net surplus compensation rate). In contrast,

Footnote continued on next page

The market-based pricing methodology adopted today allows customers to realize the benefits of changing market conditions that result in potentially lower costs. In addition, it allows generators to set the market price through the bidding process, which theoretically will ensure the price is neither too high nor too low but, instead, will be reasonable to cover the generator's costs and encourage broad participation in the market. In contrast, administratively-determined pricing is static and, as a result, can result in pricing being either too high, leading to windfalls for project developers and unnecessarily high procurement costs for customers, or pricing that is too low, preventing program subscription. These scenarios based on an administratively-determined price do not achieve ratepayer indifference to the extent achieved by Re-MAT.

Accordingly, we find that the pricing mechanism adopted today complies with "ratepayer indifference" set forth in § 399.20(d)(3) by reflecting the supply and demand of the renewable generation market.

6.11. First-Come-First-Served

Re-MAT is consistent with the requirement that electric corporations make FiT tariffs available on a "first-come-first-served basis." The "first-come-first-served" requirement is set forth in § 399.20(f). In accordance with the rules of statutory construction, this provision must be read in manner consistent with all other provisions of the statute. This provision can not be applied to the § 399.20 FiT Program in isolation. For example, it is an untenable reading of that statute that contracts be accepted by electrical corporations on a first-come-first-served

Sustainable Conservation notes that some technologies, such as bioenergy, are still maturing and have not necessarily experienced cost decreases.

basis without regard to price. Price is a key component of the statute and, only after generators enter into contracts under the adopted pricing mechanism and any other statutory prerequisites, would the first-come-first-served provision apply.

On the other hand, this provision functions to restrict the Commission from creating program requirements that interfere with the first-come-first-served requirement as it applies to the program as a whole. For example, as discussed earlier in this decision, in the absence of any specific legislative directive, a Commission requirement that pricing be distinguished based on technology-specific basis would interfere with the application of the statutory provisions requiring first-come-first-served. The statute, however, allows for first-come-first-served on a product specific basis because the statute specifically directs the Commission to consider the value of different electricity products including baseload, peaking as-available, and non-peaking as-available electricity.[70]

For these reasons, we find that Re-MAT, which includes consideration of product types but not specific technologies, is consistent with the first-come-first-served provision set forth in § 399.20(f).

7. Increase the Size of Eligible Facility to 3 MW

This decision implements the statutory amendments by increasing the maximum size of the eligible facility to 3 MW.

As originally enacted by AB 1969, § 399.20(b)(2) applied to facilities with an effective capacity of not more than 1.5 MW. In D.07-07-027, the Commission

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[70] § 399.20(f).

implemented a program under § 399.20 with a capacity limitation of 1.5 MW. SB 32 increased the capacity to 3 MW but the Commission has not yet implemented this change. SB 2 1X made no change to this provision of § 399.20.

SunEdison, Silverado Power, Solar Alliance, and Vote Solar Initiative support increasing the project eligibility to 3 MW and either find no potential reliability issues or suggest any system impact issues to the electrical grid will be addressed through the interconnection process under Tariff Rule 21 or the applicable federal rules. PG&E also supports increasing the capacity limitation of the program and indicates that it is unaware of any existing reliability issues, although increased reliance on this program and others may raise reliability concerns in the future. DRA supports the increase as offering an opportunity for economies of scale and therefore lower pricing.

Clean Coalition supports increasing the capacity beyond the 3 MW capacity limitation in the statute and suggests the Commission, on its own authority, further increase the capacity limitation to 5 MW. Clean Coalition points to expedited interconnection processes that apply to projects up to 5 MW to justify its request. Joint Solar Parties support an increase to 5 MW. Sustainable Conservation points to the benefits to the grid offered by the increased project size and to developers in terms of financial viability.

Several parties raise concerns about opening the program to larger generators. SDG&E states that to increase the size of eligibility, the Commission would need to: (1) ensure that generators continue to carry the costs of electrical system upgrades; (2) subject projects larger than 1.5 MW to the same security requirements as bidders in the standard RPS solicitation; (3) adopt delivery guarantees and damage provisions to allow the utility to manage its resource planning; and (4) apply the CAISO penalty provisions to ensure developers

provide accurate schedules. SCE generally agrees with SDG&E that increased capacity will result in increased costs for electrical system upgrades.

CALSEIA states that the increase in size of the eligible facility should occur gradually to promote projects located close to load centers and that the utilities should be authorized to request bidders to modify project size to facilitate increased grid reliability. CALSEIA requests the Commission direct the electric utilities to work cooperatively with potential distributed generation projects to assist developers in identifying locations where the addition of renewable generation of a particular size will improve system reliability. CALSEIA explains that coordination will assist developers with the overall success of project development at the lowest costs.

We find that increasing the maximum project size to 3 MW is reasonable based on the Commission's obligation to implement the provisions of the statute and note that any reliability concerns triggered by individual generating facilities are appropriately identified and mitigated within the interconnection process. We decline to adopt a 5 MW program size limitation since the plain language of § 399.20(b)(1) clearly defines the effective capacity of not more than 3 MW.

We disagree with CALSEIA's recommendation to increase the size of eligible facilities gradually until the size of 3 MW is reached. We find no connection between a gradual increase in project size and CALSEIA's objective to encourage generation to locate near load centers. We do, however, find that today's implementation of the requirement that generation be "strategically located," per the statute, will achieve the goal of encouraging load to locate near load centers. The meaning of "strategically located," is further discussed in Section 6.9. Furthermore, neither CALSEIA nor any other party provided evidence that increasing the size to 3 MW will negatively impact grid reliability.

For these reasons, we do not adopt CALSEIA's recommendation to gradually permit an increase in project size.

Sierra Club makes a brief argument that the FiT maximum project size should be determined by "the amount of generating capacity that can be reliably generated." Sierra Club, however, does not explain how to determine the amount of capacity that can be "reliably generated" nor does Sierra Club state the benefits of such a policy. Accordingly, we do not adopt Sierra Club's proposal but note that Sierra Club's comments highlight the need for additional clarity around what facilities fall within the 3 MW size limit. Today we clarify that the 3 MW AC size limitation corresponds to the nameplate capacity of the facility.

We note further that the 3 MW size is aligned with the general framework of the proposed settlement revising Rule 21 (filed in R.11-09-011 on March 16, 2012). As we have stated in R.11-09-011, exporting generating facilities do not have a clear path to interconnection under the presently effective Rule 21.[71] The May 16, 2012 settlement's proposed revisions to Rule 21 would expressly permit exporting facilities sized up to 3 MW in SCE's and PG&E's service territories and 1.5 MW in SDG&E's service territory to be evaluated under the Fast Track process.[72] While the Commission has not yet acted on the proposed interconnection settlement in R.11-09-011, the proposed Fast Track size limits

[71] R.11-09-011 at 4-5.

[72] *Motion for Approval of Settlement Agreement Revising Distribution Level Interconnection Rules and Regulations*, Proposed Revised Rule 21 at Section E.2.b.i.

would advance the statutorily required "expedited interconnection" for resources in this program.[73]

Accordingly, PG&E, SCE, and SDG&E shall add a provision reflecting the increase in eligible generator projects to 3 MW to the FiT Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision submitted by the utilities and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

8. Prohibition Against "Daisy-Chaining" to Evade Project Size Limitations

TURN, CUE, SunEdison, CALSEIA, and other parties raise the concern that project developers may break up larger projects into smaller pieces or "daisy-chain" in order to evade the size restriction. TURN and CUE suggest that utilities be given the authority to deny a tariff request pursuant to § 399.20(n) if the project appears to be part of a larger overall installation by the same company or consortium in the same general location. TURN also suggests that the Commission direct the utilities to add a provision titled "Seller Representation" that requires the seller to attest that the project represents the only project being developed by the seller on any single or contiguous piece of property.

We agree with TURN, CUE, CALSEIA, and SunEdison that additional measures must be taken to prevent daisy-chaining and agree with the concerns raised regarding daisy-chaining to evade the project size restrictions.

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[73] § 399.20(e).

Accordingly, the utilities shall add a provision titled, generally, "Seller Representation" to the § 399.20 FiT Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision submitted by the utilities and in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision. This provision shall, at a minimum, require the seller to attest that the project represents the only project being developed by the seller on any single or contiguous piece of property. This provision shall also give utilities the authority to deny a tariff request pursuant to § 399.20(n) if the project appears to be part of a larger overall installation by the same company or consortium in the same general location. Lastly, this provision shall permit generators to contest a denial under § 399.20(n) through the Commission's standard complaint procedure set forth in the Commission's Rules of Practice and Procedure.

9. Eliminate Overlap of the Commission's RAM Program and § 399.20 Program

As discussed in more detail below, any overlap between the RAM Program adopted in D.10-12-048 and the § 399.20 FiT Program is eliminated. Under D.07-07-027, Commission's § 399.20 FiT Program has, until today, only applied to facilities up to 1.5 MW. However, this decision increases the size of the eligible facilities under the FiT Program to 3 MW.[74] The RAM Program, as adopted in D.10-12-048, applies to renewable generation from 1 MW to 20 MW.

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[74] As originally enacted by AB 1969, § 399.20(b)(2) applied to facilities with an effective capacity of not more than 1.5 MW. In D.07-07-027, the Commission implemented a program under § 399.20 with a capacity limitation of 1.5 MW. SB 32 increased the capacity to 3 MW.

Therefore, unless today's decision modifies the RAM Program, these two programs will overlap for projects 3 MW and under.

Some parties, including SCE and TURN, expressed concern regarding the overlap of these two renewable programs and the potential for gaming of the price of the two programs for projects of 3 MW and under. For example, as SCE points out, a bidder in the RAM Program who is eligible under § 399.20 would never bid below the FiT price because it knows it could go back to the FiT Program and receive that price. Moreover, a bidder would have more ability to inflate a bid in the RAM Program because it would be able to fallback to the FiT Program.

We find that the most effective means of preventing potential gaming is to prohibit generators with a nameplate capacity of 3 MW[75] and under and that meet other eligibility criteria for the FiT Program, from participating in the RAM Program if the capacity for the relevant FiT product type has not yet been reached. This approach was recommended by SCE and TURN. This restriction will also eliminate a duplicative procurement mechanism for these small renewable generators. The potential duplication would also increase administrative burdens and complicate the implementation process for program participants and the Commission.

Accordingly, within 90 days of the effective date of this decision, PG&E, SCE, and SDG&E shall file a Tier 1 Advice Letter restricting RAM to generators with a nameplate capacity of greater than 3 MW. This change will not affect the

[75] The 3 MW AC size limitation corresponds to the nameplate capacity of the facility.

upcoming RAM auction scheduled to close in May 2012 but will take effect in time for the third RAM auction scheduled for the end of 2012.

10. Project Viability Criteria for § 399.20 Feed-In Tariff Program

In March 2011 briefs, SunEdison, CALSEIA, and Joint Solar Parties suggested that the Commission adopt a means to ensure that only viable projects participate in the program. The Clean Coalition, FuelCell Energy, CEERT, and Silverado Power agreed that it is a critical issue to target viable projects since the amount of capacity in the § 399.20 FiT Program is limited. These parties stated that increasing the viability of contracts executed pursuant to this program will allow for more efficient management of the limited program capacity and benefit the market by reducing speculative contracts.

SunEdison recommends establishing project viability criteria similar to those relied upon in the RAM Program. Agreeing with the need for project viability criteria, CALSEIA requests that the Commission adopt rules to prevent generators from taking advantage of the "first-come-first-served" rule to gain priority while projects may be less than viable. Likewise, the Renewable FiT Staff Proposal recommends project viability criteria, consistent with suggestions by parties. The Staff Proposal and other parties recommend the following project viability criteria:

1) <u>Bid fee:</u> $2/kW bid fee;
2) <u>Interconnection:</u> System Impact Study, Phase I study, or passed the Fast Track screens or supplemental review;
3) <u>Site Control:</u> Attest to: 100% site control through (a) direct ownership, (b) lease, or (c) an option to lease or purchase that may be exercised upon contract execution;
4) <u>Development Experience:</u> Attest that: one member of the development team has (a) completed at least one project of

similar technology and capacity or (b) begun construction of at least one other similar project;

5) Online Date: 24 months with one 6-month extension for regulatory delays;

6) Seller Concentration: An individual seller may not subscribe to more than 10 MW of capacity across the program. CALSEIA and PG&E suggest a seller concentration cap of 10 MW per seller. Staff agrees that there should be limit, but recommends a different metric. Staff proposes a seller be limited to 25% of an IOU's total capacity cap; and

7) Commercialized Technology: Attest that: project is based on commercialized technology with at least two installations in the world.

This decision adopts the above-noted project viability criteria 1 through 6. No viability criterion is adopted for commercialized technology (number 7 above). We find that the project viability criteria adopted today will assist in ensuring that projects seeking to participate in the FiT Program will come online, which supports our fifth policy guideline: increase probability of successful projects by establishing project viability criteria.

This decision adopts a seller concentration limit of 10 MW per seller because of the limited number of MWs available for the program. The definition of seller should be further explored in the standard contract phase of this proceeding. We also envision the other program requirements, such as "strategically located" and the three product types, which are discussed elsewhere in this decision, to encourage a diversity of sellers and technologies in the program.

The decision also does not adopt a requirement that the project be based on commercialized technologies. While we expect most projects to utilize commercialized technologies, the FiT Program seeks to provide an opportunity

for emerging technologies to develop on a small scale and at a reasonable price. No reason exists to preclude new or emerging technologies from the FiT Program by adopting a commercialized technology requirement.

Accordingly, PG&E, SCE, and SDG&E shall add a provision reflecting the adopted project viability criteria to the § 399.20 FiT Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision submitted by the utilities and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

11. Applicability of the § 399.20 Feed-in Tariff Program to Small Electric Utilities

This decision implements SB 380 and SB 32 by removing electric corporations with less than 100,000 service connections from the § 399.20 FiT Program.

SB 380 amended § 399.20 by adding subsection (h) which authorizes the Commission on a discretionary basis to modify or adjust the requirements of § 399.20 for any electrical corporation with less than 100,000 service connections. SB 32 recasts this same provision by combining it with subsection (c) and leaving the language unchanged. SB 2 1X makes no changes to this provision.

In response to various ALJ rulings, parties provided comments on implementation of this provision. The California Association of Small and Multi-Jurisdictional Utilities (CASMU)[76] requests that the Commission rely on

[76] CASMU includes Bear Valley Electric Service (U913E), a division of Golden State Water Company, California Pacific Electric Company, LLC (U933E) dba Liberty Energy,

Footnote continued on next page

§ 399.20(c) to exempt electric corporations with less than 100,000 service connections from the requirements of § 399.20. CASMU indicates that its members operate with between approximately 700 and 46,000 service connections within the state. Some of these utilities provide additional service connections in other states. CASMU further indicates that the combined obligation of all CASMU members under the existing § 399.20 FiT Program, as implemented by D.07-07-027, is small, only 0.599% or 1.497 MW and that under SB 32 with the increased program size, this total would only increase to approximately 3 MW, which CASMU argues is still very low. The § 399.20 FiT Program offered by CASMU members remains limited in other respects as these utilities currently only offer feed-in tariffs for water and wastewater facilities and not the expanded customer base authorized by D.07-07-027. FuelCell Energy supports an exemption because the costs associated with administering this program outweigh the proportionate share of participation.

Other parties, such as SunEdison, CALSEIA, and Sustainable Conservation, suggest that participation by small electric corporations remain voluntary because, although small, it continues to be an important component of reaching the state's 33% renewable goal. The largest electric corporations did not present a unanimous position on this topic. PG&E and SDG&E did not comment. SCE claims that the smaller electric corporations are legally required

California Pacific Electric Company, and PacifiCorp (U901E) dba Pacific Power. CASMU group no longer includes Mountain Utilities (U906E) as D.11-06-032 approved a sale and transfer of control of assets and relieved Mountain Utilities of its obligation to provide public utility electricity service.

to participate because the exemption in subsection (c) just applies to parts of the program, not the entire program.

We find that the plain language of § 399.20(c) provides the Commission with authority to modify the program as applied to small electrical corporation in a manner that includes fully removing these utilities from the program. The language permits the Commission to "modify or adjust" the requirements of § 399.20 as applied to small electrical corporations. We find that modifying the program by removing these utilities is justified because the costs of administering this program for the smaller utilities outweigh any potential benefit from their contribution, of approximately 3 MW, to the overall program.

We disagree with parties, such as SCE, to the extent they claim that modification does not mean exempting these utilities from the program. Subsection (c) provides the Commission with latitude in interpreting this provision and, with these smaller utilities only contributing approximately 3 MW, we find it reasonable to relieve them from the administrative burdens associated with the program. Currently, no customers are served under these tariffs. These smaller utilities are not prohibited from seeking authority to provide a voluntary program, separate from the FiT Program, consistent with all applicable laws and regulations.

Accordingly, within 90 days of the effective date of this decision and pursuant to § 399.20(c), electrical corporations with less than 100,000 service connections within this state shall file Tier 1 Advice Letters withdrawing their tariffs relevant to the § 399.20 FiT Program.

12. Statewide Capacity Program Cap Increased to 750 MW and Allocation of Proportionate Share to Commission Regulated Utilities

This decision implements the statutory amendments by increasing the program cap to 750 MW and allocates the proportionate share of the 750 MW (with a proportionate share designated for publicly owned utilities) to the three largest electric utilities regulated by the Commission. The allocations are made in accordance with the methodology adopted in D.07-07-027, as follows: PG&E 218.8 MW; SCE 226 MW; and SDG&E 48.8 MW, for a total of 493.6 MW.[77] We make no determinations regarding the implementation of § 399.20(f) to the extent it refers to publicly owned electric utilities provided for under § 387.6.

As originally enacted by AB 1969, § 399.20(e) required each electric corporation to offer service or tariffs under this code section until it had met its "proportional share" of the total megawatts subject to § 399.20. The total amount subject to § 399.20(e), as originally enacted, was 250 MW. The Commission implemented a program with a 250 MW cap in D.07-07-027 for public water and wastewater customers. In implementing the 250 MW cap, D.07-07-027 allocated these megawatts among the utilities regulated by the Commission for public water and wastewater customers. D.07-07-027 and D.08-09-033 expanded the program to all customers in the service territories of SCE, PG&E, and SDG&E, and allocated an additional 248.4 MW to these customers.

These utilities were, in turn, responsible for entering into contracts with generators for, at a minimum, the amount of megawatts allocated to them under D.07-07-027 and D.08-09-033. SB 380 increased the program cap to 500 MW and

[77] Based on subscriptions to date, the remaining MWs in the FiT Program are as follows: PG&E – 111 MW; SCE – 149.7 MW; SDG&E – 30 MW.

SB 32 increased the program cap again from 500 MW to 750 MW. At that time, the Commission did not implement these increases by modifying its existing program. The existing program remained capped at 250 MW for public water and wastewater customers and 248.4 MW for all other customers in the large utilities' service territories. SB 32 renamed the relevant subsection from subsection (e) to subsection (f) and included local publicly owned electric utilities. SB 2 1X makes no further modifications to § 399.20(f).

Below we discuss implementing the 750 MW program cap, the existing allocation methodology adopted in D.07-07-027, our allocation methodology adopted today going forward, and several related issues raised by parties.

12.1. Program Cap of 750 MW

Most parties, including CWCCG, Silverado Power, DRA, PG&E, SCE, and SDG&E, support increasing the program cap to the statutory limit of 750 MW. We agree and, accordingly, consistent with the statutory directive in § 399.20(f), increase the program capacity from the existing amount, as implemented in D.07-07-027, of 250 MW to 750 MW. Many parties, even those that support the increase to 750 MW, raise various questions related to implementing the increased cap. We address these various questions below.

We do not adopt the recommendation by some parties, including Vote Solar Initiative, Solar Alliance, Sierra Club, and Clean Coalition, to increase the cap beyond 750 MW. The Legislature created a specific program under § 399.20 limited to 750 MW and this program is, notably, a must-take obligation by utilities and the renewable generation procured under this program has cost implications for ratepayers. Therefore, today we set as our goal implementing the plain language of the statute and the 750 MW cap noted therein. Our decision today also rests upon our goal of achieving "ratepayer indifference" and

cost containment within the program. We are sensitive, however, to the fact that the program's MW may quickly be subscribed. In that situation, we will consider proposals from parties to expand the program.

We clarify, however, that for amounts that exceed a utility's proportionate share of the 750 MW cap, the statute does not prohibit utilities and generators from voluntarily entering into contracts. The Commission would review these contracts under the standard of review used for general renewable procurement.

We also clarify that the 750 MW cap applies on a statewide basis. As described in § 399.20(f), 750 MW is a "statewide" cap, not a service territory cap or a cap that solely applies to Commission regulated utilities. As such, based on the clear statutory language, we reject the argument made by CEERT and others that the entire 750 MW cap only applies to IOUs and that publicly owned electric utilities are subject to a separate cap. Under the provisions of the statute, the 750 MW is to be split on a proportional basis between investor owned and publicly owned electric utilities.

Furthermore, other parties, such as Clean Coalition and CEERT, suggest that the 750 MW cap is an amount in addition to the existing 250 MW cap enacted under AB 1969 and implemented by the Commission in D.07-07-027. We disagree. Again, we find that the plain language of the statute establishes a total cap of 750 MW for the entire § 399.20 Program and, accordingly, does not provide for an additional cap of 250 MW.

Some parties, including SunEdison and Joint Solar, recommend that the Commission incrementally release available capacity in the program over a two-year period, with a new release every six months. We agree, in part, with this recommendation. This issue is addressed within the pricing proposal adopted by today's decision.

Various parties, including Vote Solar Initiative and FuelCell Energy, raise issues related to the treatment of projects that are already under contract in the existing AB 1969 program. We find that all capacity already under contract from the existing § 399.20 FiT Program must be subtracted from each utility's total capacity allocation. If a contract is terminated at a future date, then the utility is obligated to re-contract for that capacity.

12.2. Capacity Allocation Methodology in Decision 07-07-027 Adopted

This decision adopts the existing allocation methodology previously adopted by the Commission in D.07-07-027 when implementing AB 1969.

In D.07-07-027, the Commission determined that 250 MW, which represented the statewide capacity requirement under § 399.20 (before SB 32), be allocated according to coincident peak demand, meaning the regulated utilities share of total system-statewide peak.

In general, parties support retaining the existing allocation methodology while updating the coincident peak demand data to at least 2009. Some parties, however, support a different methodology. SCE suggests relying on each utilities' prior three year historical peak load compared to the sum of all utilities' peak load because average historical data will mitigate year-to-year volatility. SCE also suggests reliance on actual peak load, rather than coincident peak to again, provide more reliable comparisons. PG&E suggests relying on a utility's actual retail peak demand divided by the total statewide peak demand.

We find these suggestions have merit but do not offer sufficient benefits to warrant a change in the existing allocation methodology. The current methodology is very similar to the above suggestions and, in the interest of

consistency and administrative simplicity, we find that retaining the existing allocation methodology going forward is reasonable.

Several factors must be considered in applying the existing allocation methodology to the current situation. At the time the Commission issued D.07-07-027, § 399.20 did not require participation by publicly owned electric utilities. Now, under the amendments to § 399.20 enacted by SB 32, the program's statewide cap of 750 MW applies to IOUs and publicly owned electric utilities. The addition of publicly owned utilities will impact the amount of capacity allocated to Commission-regulated utilities.

12.3. Allocated Amount - Investor Owned Utilities

Table 1
Share of Investor Owned Utilities § 399. 20(f) Capacity Allocation – 750 MW Statewide Program Cap

Electrical Corporation	Share of 750 MW	Capacity Allocated
Pacific Gas and Electric Company	29%	218.8 MW
Southern California Edison Company	30%	226 MW
San Diego Gas & Electric Company	6%	48.8 MW
Publicly Owned Electric Utility (§ 387.6)	See discussion herein on § 387.6	See discussion herein on § 387.6

To determine the above, the Commission relied upon the following data:

(1) 2010 Coincident Peak-Hour Demand:[78]

SDG&E: 3,953 MW
PG&E: 17,742 MW
SCE: 18,342 MW

(2) Total Statewide Demand:

Summer 2010 Peak: 60,797 MW[79]

(3) Determining Each Utility's Share:

Formula: 2010 Coincident Peak-Hour Demand/Total Statewide Demand = § 399.20 FiT Program Percentage x Program Cap = Program Share

SDG&E: 3,953 MW/60,797 = 6% x 750 = 48.8 MW
PG&E: 17, 742 MW/60,797 = 29% x 750 = 218.8 MW
SCE: 18,342 MW/60, 797 = 30% x 750 = 226 MW

Total Investor Owned Utilities Share: 48 + 218.8 + 226 = 493.6 MW

(4) Former § 399.20 FiT Program Allocation (with a 500 MW program cap):

SDG&E: 8% or 20 MW
PG&E: 41% or 209.2 MW
SCE: 49% or 247.6 MW

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78 *Information for most recently available year of 2010 from*: Utility Capacity Supply Plans (2011) http://energyalmanac.ca.gov/electricity/s-1_supply_forms_2011/ (scroll through excel spreadsheets for each utility's data).

79 *Information for most recently available year of 2010 from*: Summer 2010 Electricity Supply and Demand Outlook, CEC-200-2010-003, at 3 (May 2010) http://www.energy.ca.gov/2010publications/CEC-200-2010-003/CEC-200-2010-003.PDF

12.4. Set Aside of Allocated Capacity for Specific Technologies

We decline to adopt a set-aside (or carve-out) of capacity for specific technologies. AECA, CWCCG, FuelCell Energy, Sustainable Conservation, GPI, and CEERT support a set-side (or carve-out) of capacity for specific technologies. The recommendations vary.

AECA recommends that the Commission reserve 150 MW of the total 750 MW program cap for biogas generation projects at California dairy, food processing, and wastewater treatment facilities. Sustainable Conversation and GPI offer a similar recommendation. FuelCell Energy recommends that 20% of each utility's share of the 750 MW total be set aside for biogas. AECA's recommendation to reserve 150 MW is tied to a pricing proposal for biogas that is intended to make this initial 150 MW of biogas project more competitively priced. This proposal is also tied to AECA's broader recommendation that the Commission adopt processes to encourage the growth of the biogas industry. CWCCG also supports a set-aside of the program cap for biogas as a means to spur industry growth.

Other parties, such as, PG&E, SCE, SDG&E, TURN, DRA, and Constellation NewEnergy, Inc. oppose the technology-specific set-aside recommendations. These parties assert that nothing in the statute allows for technology specific set-asides. They further point out that the Legislature had the opportunity to create a set aside but did not and, instead, created a program for all eligible resources under 3 MW. These parties urge the Commission to create a level playing field for equal participation in the program by all eligible technologies.

Today, we decline to adopt a set aside for any specific technology. As created by the Legislature, the § 399.20 Program applies equally to all electric generation facilities and must be made available on a first-come-first-served basis. Subsection (f) of § 399.20 provides, in relevant part, that "An electrical corporation shall make the tariff available to the owner or operator of an electric generation facility within the service territory of the electrical corporation, upon request, on a first-come-first-served basis, …" In the absence of any statutory provision directing us to consider a set-aside, we find that a set-aside program for a particular technology is inconsistent with the technology-neutral language of the statute and requirement that the program be made available on a first-come-first-served basis.

However, as discussed previously, we seek to support the development of different renewable technologies, and, therefore, we adopt three product types within today's expanded FiT Program. This provides benefits to the IOUs because they can procure FiT resources consistent with their need and the value that each product provides. In addition, it dedicates a certain portion of the capacity allocation to each product type, which could be viewed as a set-aside that is, nevertheless, consistent with § 399.20(d)(2)(C).[80] The Re-MAT pricing mechanism could benefit bioenergy, biogas, forest biomass, and the other technologies because it allows renewable resources to compete against other similarly-valued renewable resources, rather than the entire renewable market.

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[80] § 399.20(d)(2)(C) provides that the Commission shall establish a methodology to determine the market price of electricity in consideration of, among other things, the value of different electricity products, including baseload, peaking, and as-available electricity.

As the Re-MAT pricing mechanism adjusts to market conditions, it is probable that the prices for each product type will differ. The result is that bioenergy projects, for example, could receive prices that are different than those available to solar projects that may seek a contract from a different product type.

Accordingly, based on the current statutory language, we do not adopt a technology specific set aside for the portion of the 750 MW allocated to the IOUs under this program. We do, however, seek to promote these technologies within the guidelines of the statute.

12.5. Future Adjustments in Allocation of 750 MW Cap

We decline to adopt a mechanism for future adjustments in the capacity allocation of the 750 MW adopted in today's decision. Some parties recommend that the Commission adopt a methodology for periodic updates to the allocation methodology to account for, among other things, changes in a regulated utility's share of statewide peak demand. These parties state that more accurate allocation will be achieved in this manner. In D.07-07-027, the Commission did not elect to adopt a methodology for periodic updates of the allocation methodology on the basis that the costs devoted to regular updates would likely exceed benefits. We continue to find merit in the cost-benefit assessment set forth in D.07-07-027. For these reasons, we do not adopt a mechanism for future adjustments in capacity allocation.

13. Separate Tariffs for Public Water or Wastewater and other Program Participants Eliminated

This decision directs PG&E, SCE, and SDG&E to combine existing tariffs setting forth their § 399.20 FiT Program into a single tariff for each utility.

The § 399.20 FiT Program, as originally enacted by AB 1969, was limited to "electric generation facilities," as defined therein, owned and operated by a

public water or wastewater agency. In D.07-07-027 and D.08-09-033, the Commission applied the "owned and operated" requirement to include other generators, beyond public water or wastewater agencies and directed regulated utilities to maintain two sets of tariffs on file with the Commission under § 399.20: one set of tariffs for generation owned and operated by public water or wastewater agencies and a second set of tariffs for generation owned and operated by other types of renewable generators. As a result of this directive in D.07-07-027 and D.08-09-033, the three largest regulated electric utilities currently have two § 399.20 FiT Program rate schedules on file with the Commission.

Now is the appropriate time to consolidate these tariff schedules. SB 380 amended § 399.20(b) by removing the requirement that electric generation facilities be owned and operated by a public water or wastewater agency. Subsequent amendments to § 399.20(b), including SB 32 and SB 2 1X retain the following language: "As used in this section 'electric generation facility' means an electric generation facility located within the service territory of, and developed to sell electricity to, an electrical corporation that meets all of the following criteria:…"[81]

Overall, parties support the recommendation to consolidate tariff schedules. Consolidation of tariffs will decrease transaction costs by simplifying the administration of the program. In addition, based on the removal of the language in § 399.20 restricting the program to public water or wastewater agencies, we find no legal reason exists to maintain two separate tariff schedules and find it reasonable to direct PG&E, SCE, and SDG&E to consolidate the two

[81] Additional criteria are omitted and are not relevant for purposes of this discussion.

schedules. Any related conforming changes to the § 399.20 FiT Program contracts must also be implemented. This direction to consolidate tariffs does not apply to the small utilities because we have directed them in Section 11 of this decision to withdraw their tariffs related to § 399.20.

Accordingly, PG&E, SCE and SDG&E shall modify tariff and contract provisions to reflect the consolidation of tariffs applicable to public water or wastewater agencies and tariffs for other customers into the § 399.20 FiT Program. These modifications shall be incorporated into the standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review these provisions submitted by the utilities and, in a separate decision accept, reject, or modify the provisions. Related FiT tariff modifications will also be addressed in this separate decision.

14. Retail Customer Requirement Eliminated

This decision implements SB 32 by eliminating the requirement that participating generators be retail customers to participate in the § 399.20 FiT Program.

As originally enacted by AB 1969, § 399.20(b) required electric generation facilities to be, among other things, owned and operated by public water or wastewater agencies and a "retail customer" of an electrical corporation. SB 32 replaced the phrase "retail customer" with "located within the service territory of, and developed to sell electricity to …"[82] SB 32 also changed § 399.20 by eliminating the requirement that the facilities be owned and operated by public

[82] § 399.20(f).

water or wastewater agencies. We address this change elsewhere in this decision. Now we focus on the replacement of the phrase "retail customer." SB 2 1X retains the modifications made by SB 32.

As a result of the SB 32 amendments, we now find that, according to the clear language of § 399.20, the program is not limited to retail customers of the electrical corporation and, instead, available to those that are owners or operators of the electric generation facility. The majority of parties support implementation of SB 32 under this interpretation. Silverado Power points out that eliminating the retail customer requirements will expand the options under the § 399.20 FiT Program to include, for example, locations in so-called brown fields with no existing load or customer. Similarly, FuelCell Energy points out that, in the absence of the retail customer requirement, an otherwise eligible biogas generator could be sited at an abandoned landfill or dairy digester that is not an existing retail customer of the purchasing utility. DRA also points to expanded opportunities for the program. We agree that expanded possibilities exist and do not attempt to identify them all here.

Some parties request additional clarifications of the statute based on the elimination of the "retail customer" requirement. SunEdison and Joint Solar Parties request further clarification on whether third-parties can participate in the § 399.20 FiT Program. We clarify that generating systems owned and operated by third-parties (and not the retail customer of record) are eligible to participate in the § 399.20 FiT Program.

We disagree, however, with SunEdison's and Joint Solar's interpretation of statutory language to mean that SB 32 prohibits the sale of excess generation. SunEdison and Joint Solar Parties claim that the phrase in § 399.20(b) "developed to sell electricity to, an electrical corporation" together with the recent

elimination of the "retail customer" requirement, means that the Legislature only intended "full" sales (not excess sales) under the § 399.20 FiT Program. However, that statute is silent on these types of sales. If the Legislature intended to limit excess sales it could have done so. Therefore, because the plain statutory language does not prohibit excess sales, we reject the interpretation proposed by SunEdison and Joint Solar.

As a result, PG&E, SCE, and SDG&E are required to offer generators two options: either full sales or excess sales. The nameplate capacity, however, of all generators participating in this program is limited to 3 MW, regardless of the sales option.

Accordingly, PG&E, SCE, and SDG&E shall remove, as necessary, references to retail customers in the FiT Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision submitted by the utilities and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

15. Inspection and Maintenance Report – Annual Requirement Adopted

This decision implements SB 32 by adding an inspection and maintenance provision to the tariffs and the power purchase agreements under the § 399.20 FiT Program.

SB 32 amends § 399.20 by adding an inspection and maintenance provision at subsection (p) of § 399.20. Section 399.20(p) provides that the "owner of the electric generation facility receiving a tariff pursuant to this section shall provide an inspection and maintenance report to the electrical corporation at least once

every other year." SB 2 1X makes no changes to this provision. Section 399.20(p) further provides that this inspection and maintenance report be prepared by a California-licensed electrician who is not the owner or operator of the facility and that the report must be prepared at the expense of the owner or operator.

All parties agree that § 399.20(p) requires an inspection and maintenance report by a California-licensed electrician who is not the owner or operator of the facility. We find this interpretation of the statute consistent with the plain language of the statute and, therefore, reasonable.

Parties disagree on some of the implementation details of § 399.20(p), such as the appropriate time interval between reports. PG&E, SCE, and SDG&E propose annual reporting, which they argue is consistent with the plain statutory language. AECA, CALSEIA, and FuelCell Energy propose reporting once every two years (biennially) rather than annually because annual reporting would be duplicative, burdensome, and costly.

The language of the statute does not provide definitive direction on this question. However, we find annual reporting, rather than a longer time interval, reasonable based on the importance of proper maintenance of the electric system.

Joint Solar Parties and SunEdison suggest that, to avoid unnecessary duplication, the Commission coordinate the § 399.20(p) report with any required reports required under the Tariff Rule 21. We acknowledge that possible efficiencies may exist in such coordination. However, because the Commission is currently engaging in efforts to revise Tariff Rule 21 in R.11-09-011, we find it more appropriate to attempt to coordinate the reporting requirements after the Rule 21 revision is complete. Therefore, parties should bring any required coordination issues to our attention in either R.11-09-011 or in this proceeding at that time.

We do not at this time accept the recommendation of some parties, such as PG&E and the Californians for Renewable Energy (CARE), that we adopt a standardized form for this report. While efficiencies might be gained, we find the particularities of safety and reliability matters are better left to the individual utilities but we support the utilities' own efforts to coordinate on this issue and create a standardized form.

FuelCell Energy recommends the confidential treatment of these reports but provides no specific basis for its request. No other parties commented on this issue. Accordingly, in the absence of a showing that the confidential treatment is needed to protect a specific aspect of the market or the report, we deny this request.

As recommended by the utilities, we find that language concerning inspection and maintenance reporting should be included in both the FiT Program standard form contracts and tariff.

Accordingly, PG&E, SCE, and SDG&E shall add a provision reflecting the inspection and maintenance reporting to the FiT Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision submitted by the utilities and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

16. 10-day Reporting Requirement of Request for Service Under Tariff

This decision implements SB 32 by directing utilities to add a 10-day reporting requirement to their tariffs under the § 399.20 FiT Program. The information required is set forth in Attachment A.

SB 32 amends § 399.20 by adding subsection (m). Subsection (m) directs utilities to report, within a 10-day period, the receipt of a request by a generator for service under tariffs filed pursuant to the § 399.20 FiT Program. Subsection (m) provides that, within 10 days of receipt of a request for a tariff pursuant to this section, the electrical corporation that receives the request shall post (1) a copy of the request on its Internet Web site and (2) the name of the city where generation facility is located. Subsection (m) also states that information in the request that is proprietary and confidential, including, but not limited to, address information beyond the name of the city shall be redacted. SB 2 1X makes no changes to this provision.

PG&E, Solar Alliance and Vote Solar Initiative, Sustainable Conservation, and GPI, among others, support increased transparency in the process to obtain service under the § 399.20 FiT Program and, for that reason, support the public disclosure of certain information. However, as a preliminary matter, these parties request clarification from the Commission on when the 10-day reporting period begins.

The statutory language provides that this reporting period begins within 10 days of receipt of a request for a tariff. PG&E suggests that the language means that the 10-day period start when the contract is signed by both the seller and the utility. SCE supports the same interpretation because no need for public posting of information would occur, according to SCE, if a seller requested but did not ultimately enter into a power purchase agreement due to eligibility issues or other conflicts. The majority of parties provide no comments on this topic.

We agree that the pertinent language is unclear as it applies to the existing process within the § 399.20 FiT Program. Secondary legal sources, such as the

legislative history, do not provide clarification. We also agree with parties that, in implementing subsection (m), the goal should be increased transparency of the program to facilitate participation by generators. To achieve this goal, we implement subsection (m) in a manner that requires the reporting of information within 10 days of both (1) signature of a power purchase agreement by the seller (generally referred to as the "execution date") and (2) signature by both the seller and the utility (generally referred to as the "effective date").[83] We find that information pertaining to both dates is critical to providing increased transparency regarding the program. We disagree with SCE that information pertaining to contracts signed by seller but never obtaining an effective date (by obtaining signatures by both seller and utility) is not useful information. As a minimum, each utility should state on its website the number of proposed contracts and the reasons for rejection.

Regarding the type of information to be disclosed within 10 days, DRA recommends the Commission adopt a reporting requirement for § 399.20 FiT Program similar to the reporting systems already in place by PG&E and SDG&E for Project Development Status Reports. DRA does not recommend relying on SCE's current reporting system and claims it does not provide a sufficient model. The Solar Alliance and the Vote Solar Initiative identify a list of topics to be identified in the internet posting, including the city location, project name, developer name, project status, expected commercial operation date, original bid, installed capacity and other information be posted on the internet. Solar Alliance

[83] D.11-11-012 (*Decision Granting, with Modifications, the Motion by Clean Coalition for Immediate Amendments of the Southern California Edison Company AB 1969 CREST Power Purchase Agreement*) at 30.

and Vote Solar Initiative point out that this information is largely consistent with the information required by the Commission in D.10-12-048 (RAM Program) and implemented by PG&E in Advice Letter 3809-E for tracking and reporting of RAM projects. CALSEIA states that PG&E and SCE currently comply with this provision by providing the information set forth in their AB 1969 programs. SunEdison supports the position of Solar Alliance and Vote Solar Initiative to create a reporting requirement consistent with other Commission programs. SunEdison sees value in making this information publicly available so as to allow participants the ability to assess their potential participation in the program but also urges the Commission avoid duplication with Rule 21 reporting requirements. PG&E also recommended that the substance of the posting be standardized and specifically suggests that city location, capacity, expected deliveries, length of contract and other information be included. SCE recommends a list of topics similar to Solar Alliance and Vote Solar Initiative. Silverado Power suggests confidentiality may be furthered protected by release of the county rather than the city.

We find that applying the reporting requirement to topics already included in existing programs, such as the RAM Program implemented by D.10-12-048 and various advice letters, including PG&E's Advice Letter 3809-E, is reasonable because these existing reporting requirements provide efficiencies and transparency. While the statutory language does not require this level of information, it does not prohibit the Commission from requiring such disclosure and is justified by our goal of increased transparency.

The required information is set forth below. We adopt a standardized form to be used by all utilities to post the relevant information. Standardization of the form will likely reduce transaction costs and simplify access to the

information on the Internet. To avoid unnecessary duplication of the reporting requirement, we will revisit this matter if duplication with Tariff Rule 21 reporting requirements is brought to our attention in R.11-09-011.

The form to be used by all electric corporations to post information on the internet is included herein at Attachment A.[84]

Accordingly, PG&E, SCE, and SDG&E shall add a provision reflecting the 10-day reporting requirement for requests for service in the FiT Program standard form contract and/or tariff being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision submitted by the utilities and, in a separate decision accept, reject, or modify the provision. Related FiT Tariff modifications will also be addressed in this separate decision.

17. Publicly-Owned Electric Utilities – Separate Program

This decision does not adopt any feed-in tariff program requirements for publicly owned electric utilities.

SB 32 added § 387.6 to the Pub. Util. Code. Section 387.6 requires, generally, that a local publicly owned electric utility offer a tariff to owners or operators of electric generation facilities within its service territory. Parties provided comments on this issue and on the issue of whether certain issues set forth in SB 32 and SB 2 1X may benefit from coordination with local publicly

[84] The form includes seller name, project name, status (on schedule, delayed, operation, terminated), capacity alternating current (MW), expected energy production (gigawatt hours/yr) technology, contract price ($/MWh), vintage (existing, restart, repower, new), contract term (years), location (city, county), contract execution date, contractual

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owned electric utilities, such as, the calculation of proportionate share of the 750 MW program cap.

In response, the California Municipal Utilities Association (CMUA) states that the Commission has no jurisdiction over publicly owned electric utilities. CMUA further states that the Commission has no jurisdiction to calculate proportionate share of the 750 MW cap for publicly owned electric utilities and that § 387.6(e) makes clear that the Commission has no authority to determine that share. CMUA further states that no coordination is needed between the program adopted by the Commission for IOUs and the program adopted by municipalities for publicly owned electric utilities but acknowledges that feed-in tariff programs implemented by IOUs may provide informative examples for the governing boards of publicly owned electric utilities. Other parties provided no further comments.

We agree with the CMUA that based on § 387.6, the Commission has no authority to design or implement a feed-in tariff program for publicly owned electric utilities. We further agree that SB 32 increased the total § 399.20 FiT Program cap to 750 MW and allocates a portion of this 750 MW to publicly owned electric utilities. We direct PG&E, SCE, and SDG&E to work cooperatively with publicly owned utilities as needed to share information that will assist them in developing a feed-in tariff program consistent with § 387.6. As discussed above, we assert jurisdiction over IOUs and the allocation methodology relied upon to determine their share of program capacity.

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online date, actual online date, 6-month extension granted (yes or no), date of termination and reason why terminated.

18. Utility Discretion to Deny Tariff Request Under § 399.20

This decision implements SB 32 by directing utilities to incorporate a provision into their standard form contracts, which utilities and parties are currently developing, for written notice of a denial of a request for service under the § 399.20 FiT Program.

SB 32 adds subsection (n) to § 399.20 to provide the electric corporation with the ability to deny a tariff request by an electric generation facility in certain circumstances relating, generally, to compliance with the statute and ensuring the safety of the electric grid.

In its March 2011 opening brief, FuelCell Energy suggested that the Commission clarify this provision to avoid unnecessary misunderstandings and disputes. Specifically, FuelCell Energy requested that the Commission determine the point in the contracting process that a utility may deny such a tariff request. Other parties, including the Solar Alliance and the Vote Solar Initiative support further clarification but fail to provide a specific proposal with supporting rationale. These parties note the importance of clarifying the term "inadequate" interconnection point but others recognize the difficulty in establishing greater certainty.

SCE suggests that an affidavit may be sufficient means to determine compliance with subsection (n)(3). Silverado Power suggests that, in the interest of contract certainty and securing financing, that contract termination provisions only apply before a contract is executed. SDG&E states, in addition to the need for more specificity, that the language of subsection (n) would also permit a denial in other circumstances, such as a when the facility is located outside of the service territory as set forth in subsection (f).

In the interest of administrative ease and reducing transaction costs, it is important to adopt clear policies around when an electric corporation may deny a tariff request. We find that it is also reasonable to place a certain amount of discretion in the utility to carrying out subsection (n), especially since the denials are subject to a statutorily required appeal process before the Commission under § 399.20(o).[85] Neither the statutory language itself nor secondary sources further clarify this matter. At a minimum, we find that any denial of service under § 399.20(n) must be provided in writing to the producer.

Accordingly, PG&E, SCE, and SDG&E shall add a provision regarding denial of service by the utility to the FiT Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision submitted by the utilities and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

19. Contract Termination Provisions

This decision implements SB 32 by directing utilities to incorporate a provision into their standard form contract and/or tariff, which utilities and parties are currently developing, for termination of service under the § 399.20 FiT Program.

SB 32 adds subsection (l) to § 399.20 to provide for contract termination before the contract expiration date in certain circumstances. SB 2 1X makes no

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[85] § 399.20(o) provides that "Upon receiving a notice of denial from an electrical corporation, the owner or operator of that electric generation facility denied a tariff pursuant to this section shall have the right to appeal that decision to the commission."

modifications to this subsection. Subsection (l) of § 399.20 provides, generally, that the owner or operator of an electric generation facility shall continue to receive service under the tariff or contract until either of the following occurs (1) the owner or operator no longer meets the eligibility requirements for receiving service pursuant to the tariff or contract or (2) the period of service established by the Commission pursuant to subdivision (d) is complete.

Parties, such as Silverado Power, SunEdison, and Sustainable Conservation, point out that the termination provision should be narrowly interpreted and not increase the level of uncertainty by subjecting a contract to unknown or subsequently imposed eligibility requirements. SCE suggests that the language of the statute be incorporated into the tariffs and form contracts together with several other provisions. FuelCell Energy agrees with Silverado Power, SunEdison, and Sustainable Conservation that the termination provisions should be interpreted narrowly and also suggests that the Commission adopt a process for administering termination matters, pointing to the procedure established by the CEC under AB 1613. Under AB 1613, the CEC certifies eligibility of all facilities in the first instance and administers a decertification process in the event a facility falls out of compliance. Alternatively, FuelCell Energy suggests that the contract could provide for a notice provision from the defaulting party and a dispute resolution process, such as arbitration. FuelCell Energy also asks for clarification on whether a termination results in returning the capacity back into the § 399.20 FiT Program. SCE requests the Commission clarify whether terminated capacity must be replaced by additional contracts under the § 399.20 Program or replaced with capacity in another RPS program.

Consistent with the plain language of § 399.20(l) and in the interest of promoting stability of this program, it is reasonable to interpret the statute as

requiring termination of the two events described in subsection (l)(1) and (l)(2) to be included in the standard form contract and/or tariff but that the Commission will not exclude other termination rights currently being considered in this proceeding considering the joint standard form contract.[86] Regarding questions raised by parties about the need for a decertification program similar to the program under AB 1613 administered by the CEC, we find no need for such a program now. To the extent parties find that an alternative resolution process, such as that suggested by FuelCell Energy, might be appropriate, we direct parties to pursue this matter in the ongoing discussion concerning a single form contract for the program described in the January 10, 2012 ALJ ruling.

Accordingly, PG&E, SCE, and SDG&E shall add a provision reflecting contract termination to the FiT Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision submitted by the utilities and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

20. Expedited Interconnection Procedures

This decision acknowledges that expedited interconnection is critical to the success of the § 399.20 FiT Program and implements the directives set forth in

[86] § 399.20(l) provides as follows: "An owner or operator of an electric generation facility electing to receive service under a tariff or contract approved by the commission shall continue to receive service under the tariff or contract until either of the following occur: (1) The owner or operator of an electric generation facility no longer meets the eligibility requirements for receiving service pursuant to the tariff or contract; (2) The

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SB 32 pertaining to expedited interconnection by clarifying that parties should rely on the existing provisions of Tariff Rule 21 until the Commission finalizes its ongoing efforts to refine Rule 21 and expedited interconnection in R.11-09-011. In addition, we find that, until the Commission makes a final determination in R.11-09-011, utilities shall allow generators to choose which interconnection processes to use, either the process set forth in the existing Tariff Rule 21 or the FERC interconnection procedures under the Wholesale Distribution Access Tariff (referred to as "WDAT").[87] We anticipate that generators will find Rule 21, as revised in R.11-09-011, sufficient to meet the statutory mandate of expedited interconnection and, at that point, we will no longer permit interconnection under the federal tariffs. On a broad level, we briefly summarize the issues pertaining to expedited interconnection below as more specific consideration of the issues will occur in R.11-09-011.

SB 32 added subsection (e) to § 399.20 to provide that an electric corporation shall provide expedited interconnection procedures for a facility that is connected on a distribution circuit and generates electricity in a manner to offset peak demand on the electric circuit. Notably, in D.07-07-027, the Commission established a need for expedited interconnection under AB 1969 "to prevent interconnection from becoming a barrier to completion, …" and required

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period of service established by the commission pursuant to subdivision (d) is completed."

[87] The utilities use different names for their FERC-jurisdictional interconnection tariffs. SCE and SDG&E each use WDAT, while PG&E uses "Wholesale Distribution Tariff." This decision uses the term WDAT to refer to each utility's tariff.

the utilities to follow the interconnection procedures in Rule 21 or FERC interconnection procedures.[88] Parties provided comments on this topic.

In March 2011 briefs, PG&E and SCE suggest that the Commission may not be able to address this issue because connections on the distribution level are FERC-jurisdictional. PG&E further suggests that an expedited procedure for only the § 399.20 FiT Program is not appropriate because interconnection to the grid must include a comprehensive review, and also states that it will make reasonable efforts to accommodate interconnection consistent with its legal obligations. SCE points to WDAT as a possible alternative process. We agree with PG&E that interconnection must be addressed on a comprehensive level and, therefore, anticipate addressing these issues in R.11-09-011.

Furthermore, to the extent generators decided to rely on the Tariff Rule 21, the existing provisions of Tariff Rule 21 will apply, rather than any potential revised version of Rule 21, until the Commission issues a decision on potential revisions to the Rule 21 Tariff in R.11-09-011 unless a different direction is provided for in either this proceeding or in R.11-09-011 by ruling of the Administrative Law Judge or Commission decision.

IREC, the Solar Alliance, and the Vote Solar Initiative find Rule 21, in its current format, insufficient but suggest other possible models. IREC also urges the Commission to pursue consistency among the many existing interconnection procedures. FuelCell Energy suggests current efforts underway before the CAISO regarding the Generator Interconnection Procedures and the electric utilities' efforts to reform qualifying facilities' interconnection procedures are

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[88] D.07-07-027 at 40.

sufficient to address the needs under the § 399.20 FiT Program. CALSEIA recommends that the Commission monitor the electric utilities' continued progress to reform the WDAT and suggests that these reforms may be sufficient for purposes of the § 399.20 FiT Program. The Solar Alliance and the Vote Solar Initiative support reliance on the WDAT as the most viable existing option. Sustainable Conservation points out that interconnection sometimes takes a year or longer and recommends reliance on Rule 21 as an accessible means of addressing interconnection under the Commission's jurisdiction.

As stated above, we acknowledge that expedited interconnection is critical to the success of the § 399.20 FiT Program. These issues are scheduled to be addressed in R.11-09-011. However, until the Commission makes a final determination in R.11-09-011 revisions to Tariff Rule 21 that may provide a more expedited interconnection process to participants in this Program, utilities shall allow generators to choose which interconnection processes to use, either the process set forth in the Rule 21 Tariff or the WDAT. We direct this choice since the utilities follow different internal processes regarding which interconnection procedure is allowed for different renewable energy programs. By allowing generators to choose the process, generators will be able to evaluate which interconnection procedure better addresses their specific needs.

21. Refunds of Other Incentives – California Solar Initiative and Small Generator Incentive Program

SB 32 added subsection (k) to § 399.20 to require owners of eligible generation facilities to refund any incentives received from the California Solar Initiative (CSI) or the Small Generator Incentive Program (SGIP) before participating in the FiT Program. SB 2 1X made no changes to subsection (k). Parties commented on implementation of this provision.

Most parties agreed that refund of any incentives was appropriate prior to participating in this program but presented different proposals on how to implement and calculate such refunds. The calculation of an appropriate refund is sufficiently complicated and case specific that we find a reasonable approach is to adopt PG&E's proposal articulated in its November 2011comments.

Specifically, PG&E suggests that customers who participate in the CSI or SGIP be required to provide the benefits of their distributed generation installation for a period of ten years and that these customers be held to that commitment, for which they have been compensated. PG&E further suggests that instead of establishing an incentive refund structure, participants in the CSI or SGIP be ineligible for the § 399.20 FiT Program for 10 years from the date they first received the incentive. Upon completion of the 10-year commitment, if they are otherwise eligible, CSI and SGIP facilities can then participate in the § 399.20 FiT Program. Likewise, PG&E suggests that net-energy metering customers be ineligible for the § 399.20 FiT Program. Net-energy metering customers that prefer the FiT price for exports must first terminate their participation in net-energy metering.

We adopt PG&E's proposal. A generator that previously received incentives under CSI or SGIP can participate in the § 399.20 FiT Program and will owe no refund if it has been online and operational for at least ten years from the date it first received the incentive. Net-energy metering customers can participate in the § 399.20 FiT Program but must first terminate participation in net-energy metering.

Accordingly, PG&E, SCE, and SDG&E shall add a provision reflecting the eligibility to participate in the § 399.20 Fit Program based on past participation and receipt of CSI and SGIP incentives in the FiT Program standard form

contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision submitted by the utilities and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

22. FERC Certification of Generator for Qualifying Facility (QF) Status

Since this program is developed to be compliant with PURPA, a participating generator must register with FERC as a QF.[89] Generators may utilize FERC's self-certification[90] process by filling out FERC's Form 556. Generators can visit FERC's website for more information on how to self-certify as a qualifying facility.[91]

23. Transition Issues

Parties raised the issue of whether rules under the existing AB 1969 program apply to projects now in the queue or whether the rules adopted today apply.

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89 The fundamental premise of the pricing proposal adopted today is that the prices reflect avoided costs, which the Commission has authority to set under the PURPA for QFs. In the absence of such federal authority, the Commission would not have jurisdiction to establish the wholesale FiT Program prices. Therefore, to satisfy the PURPA requirements, the participating generator must be a QF. (PG&E April 16, 2012 Reply Comments.)

90 FERC provides two certification options: self-certification or FERC certification.

91 How to obtain QF Status: http://www.ferc.gov/industries/electric/gen-info/qual-fac/obtain.asp.

Silverado raised this issue and points out that it has projects currently on the wait lists for the § 399.20 FiT Program under SCE's CREST program.[92] As a result, it is unclear, from its perspective, which rules will apply to those projects. The October 13, 2011 Staff Proposal recognized this issue and acknowledges that the transition to the new rules presents complications for some generators, especially those operating under SCE's FiT Program.[93] The Staff Proposal also notes that SB 32 became effective on January 1, 2010 and, as a result, at that time generators were placed on notice that the rules of the FiT Program would change.

We agree that generators had ample notice that the rules would change. We also note that the Commission's general policy is to apply the rules in place at the time the contract is executed. No contracts exist for those projects identified by Silverado in the queue. Therefore, we find that projects in the queue and without a contract must comply with the new rules adopted today.

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[92] Silverado April 9, 2011 comments to proposed decision at 4, citing to Silverado June 27, 2011 reply comments.

[93] October 13, 2011 Staff Proposal at 19.

24. Motion for Further Consideration of an "Administratively Determined, Avoided Cost Based Pricing Mechanism" - Denied

The Joint Parties filed a motion[94] on December 19, 2011 and noted their concern that the Commission or ALJ had given the Renewable FiT Staff Proposal greater consideration or more evidentiary weight than other pricing proposals because the Staff's Proposal was presented in an ALJ's ruling dated October 13, 2011 and, in addition, was discussed at a Staff Workshop on September 26, 2011. These concerns were presented in a motion seeking further consideration in a workshop on the record of an "administratively determined, avoided-cost based pricing mechanism."[95] The motion stated that further consideration of such a pricing mechanism was needed because the ALJ's October 13, 2011 ruling, in combination with the Renewable FiT Staff Proposal, effectively demonstrated to the Joint Parties that the Staff Proposal would, in some form, prevail before the Commission.

We emphasize that the Renewable FiT Staff Proposal was one of many pricing proposals considered by the Commission in this proceeding. The Joint Parties' suggestion that the record was unduly limited by the Commission's consideration of the Renewable FiT Staff Proposal is misplaced. The Commission gave full consideration to all pricing options presented in the

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[94] *Joint Motion of the Center for Energy Efficiency and Renewable Technologies; AG Power Group, LLC; Sustainable Conservation; Agricultural Energy Consumers Association; Green Power Institute; California Wastewater Climate Change Group; California Farm Bureau Federation; Fuel Cell Energy; and FlexEnergy, Inc., for a Ruling Directing the Consideration of an Administratively determined Avoided Cost Pricing Methodology for the Renewable FIT at a January 2012 Workshop that Would be Part of the Record for the Decision on the Renewable FIT* filed December 19, 2011.

[95] *Id*. at 5.

proceeding, including that of an "administratively determined, avoided-cost based pricing mechanism."

Moreover, we emphasize that all parties had ample opportunities to present their pricing proposal to the Commission. Pricing proposals were requested in early and late March 2011 and, again, in July and August 2011. In November 2011, we sought input on pricing issues from parties. While the November 2011 comments focused on the Renewable FiT Staff Proposal, we sought input on a broad basis seeking to understand the pros and cons of the Staff Proposal as compared to various alternative-pricing proposals.

The motion is denied.

25. Petition for Modification of Decision 07-07-027 by Solutions for Utilities, Inc. - Denied

On June 18, 2010, Solutions for Utilities Inc. (Solutions for Utilities) filed a petition for modification of D.07-07-027.[96] Solutions for Utilities seeks specific changes to the mechanics of § 399.20 FiT Program as administered by SCE and as authorized in D.07-07-027. Specifically, Solutions for Utilities asks the Commission to modify SCE's standard power purchase agreement used for the § 399.20 FiT Program in various ways, including: adding curtailment provisions; deleting paragraphs 4.2, 14.2, 14.4; and striking the Interconnection Facilities and Financing Ownership Agreement (IFFOA) and the IFFOA's attachments from the power purchase agreement. Finally, Solutions for Utilities asks the Commission to remove the MPR in SCE's power purchase agreement and to change the pricing mechanism under the § 399.20 FiT Program.

[96] This petition for modification was filed in R.06-05-027. This proceeding is the successor proceeding to R.08-08-009 and R.06-03-027.

PG&E, SCE, and SDG&E responded in opposition to the petition for modification. The utilities asked the Commission to deny the petition based on the timing of the filing, since the petition was filed more than one year after the issuance of D.07-07-027. The utilities also opposed the substance of the petition.

Many of the issues framed by Solutions for Utilities' petition for modification already have been addressed in different aspects of this proceeding. The remaining issues will be addressed either in this proceeding or in the separate, ongoing Commission rulemaking on Rule 21 interconnection matters, R.11-09-011.

In this proceeding, on November 10, 2011, the Commission issued a decision granting, in part, a motion filed by the Clean Coalition to change SCE's § 399.20 FiT Program standard power purchase agreement in a manner similar to those sought by Clean Coalition's petition for modification.[97] For instance, the November 10, 2011 decision addressed a request to add curtailment provisions and delete paragraphs 4.2, 14.2, 14.4. In addition, today's decision addresses the issue of pricing under the § 399.20 FiT Program which is also framed by Solutions for Utilities' petition for modification. A future decision in R.11-05-005 will address standard terms and conditions for the § 399.20 FiT Program standard power purchase agreement. Finally, R.11-09-011 is the proper forum to address modifications to the IFFOA and other interconnection agreement issues.

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[97] *See* D.11-11-012 (*Decision Granting, with Modifications, the Motion by Clean Coalition for Immediate Amendments of the Southern California Edison Company AB 1969 CREST Power Purchase Agreement*)

Therefore, because all issues framed by Solutions for Utilities' petition for modification either have been addressed or are scheduled to be addressed in either this proceeding or in R.11-09-011, the petition is denied.

26. Petition for Modification of Decision 07-07-027 by Sustainable Conservation - Denied

On June 29, 2011, Sustainable Conservation filed a petition for modification of D.07-07-027. Sustainable Conservation's petition requests that the Commission do as follows: (1) direct the utilities to use the Tariff Rule 21 for customers that interconnect to the distribution system; (2) assert jurisdiction over the distribution-level power lines of California's electric utilities; and (3) modify D.07-07-027 to strike language giving utilities the discretion to require either Tariff Rule 21 or FERC interconnection procedures.

SCE and PG&E responded in opposition to the petition for modification due to the timing of the filing, since the petition was filed more than a year after D.07-07-027. SCE and PG&E also opposed the substance of the petition. IREC and Independent Energy Producers supported the petition's request that the Commission address the general interconnection issues raised in the petition.

The issues framed by Sustainable Conservation's petition for modification are addressed in today's decision or will be addressed in the separate, ongoing rulemaking before the Commission, R.11-09-011. We expect that the first two issues raised by the petition will be addressed, to the extent necessary, in R.11-09-011. Today's decision addresses the third issue raised in the petition. Specifically, today's decision directs the utilities to give generators a choice of which interconnection procedures to use, either the Tariff Rule 21 or the FERC interconnection tariffs.

Therefore, because the issues framed by Sustainable Conservation's petition for modification are addressed in today's decision or will be addressed in R.11-09-011, the petition is denied.

27. Comments on Proposed Decision

The proposed decision of ALJ DeAngelis in this matter was mailed to the parties in accordance with § 311 of the Pub. Util. Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on April 9, 2012, and reply comments were filed on April 16, 2012. To the extent required, revisions have been incorporated to reflect the substance of these comments.

28. Assignment of Proceeding

Mark J. Ferron is the assigned Commissioner and Regina DeAngelis is the assigned ALJ in this proceeding.

Findings of Fact

1. The June 27, 2011 ALJ Ruling, our RAM Program, and the October 13, 2011 Renewable FiT Staff Proposal contain the following five policy guidelines relevant to today's decision:

   i. Establish a feed-in tariff price based on quantifiable ratepayer avoided costs that will stimulate market demand;

   ii. Contain costs and ensure maximum value to the ratepayer and the utility;

   iii. Ensure administrative ease and lower transaction costs for the buyer, seller, and regulator;

   iv. Use existing transmission and distribution infrastructure efficiently; and

   v. Establish project viability criteria to increase probability of successful projects within the program.

2. The MPR price may be too high or too low for different FiT product types, such as baseload, peaking as-available and non-peaking as-available.

3. The MPR is a price based on a natural gas-fired electric plant, and not a renewable generator. The MPR reflects the costs of a different energy market, fossil fuels.

4. The renewable market has evolved since the Commission first established the MPR in 2003 at the beginning of the RPS Program.

5. The renewable market is sufficiently robust to serve as the point of reference for establishing the market price for small renewable projects rather than the very different market represented by the MPR, which reflects the costs of a combined-cycle natural-gas power plant.

6. The methodologies presented to determine certain adders, such as those based on technology specific generation, are largely based on general avoided societal costs, and not ratepayer costs.

7. It is not easy to quantify the general societal benefits that support specific types of renewable technologies consistent with the provisions of state law and federal law.

8. Net surplus generation is provided without a power purchase agreement on an intermittent, unpredictable, and as-available basis over a 12-month period. In addition, the Commission found that the only generation the utility avoids when a net-energy metered customer provides surplus generation is reduced electricity procurement from the short-term wholesale market.

9. This decision adopts a pricing methodology that relies upon the November 2011 renewable market power pricing information from the RAM adopted in D.10-12-048 and takes components from a number of different pricing proposals presented by parties, including IREC, SunEdison, Silverado Power, Vote Solar

Initiative, and SCE and by Staff. The pricing methodology also relies upon a two-month price adjustment mechanism to increase or decrease the FiT price for a particular product type based on market conditions.

10. A separate price for each of the three product types (baseload, peaking as-available, and non-peaking as-available) better captures the value provided by the different technology types.

11. Baseload projects provide firm energy deliveries (e.g., bioenergy and geothermal); peaking projects provide non-firm energy deliveries during peak hours (e.g., solar); and non-peaking as-available projects provide non-firm energy deliveries during non-peak hours (e.g., wind and hydro).

12. There is not enough market information for the three product types to enable us to adopt a unique starting price for each product type.

13. Adjusting the starting price by time-of-delivery factors based on the generator's actual energy delivery profile captures the value of each generator to the utility.

14. Based on the results from the November 2011 RAM auction, we anticipate that the starting price for each separate product type will be $89.23/MWh (pre-time-of-delivery adjustment).

15. The Re-MAT price should only increase or decrease if there is sufficient market interest in a product type, which may be determined by how many projects execute contracts at a particular Re-MAT price.

16. Ratepayer exposure to excessive cost due to market manipulation or malfunction is possible.

17. Temporarily suspending the program based on evidence of market manipulation or malfunction will guard against ratepayer exposure to excessive costs.

18. Allocating a utility's total capacity share to the three product types over a limited time period will serve to stimulate the market for small renewable distributed generation by providing an adequate supply of available capacity to each product type.

19. The total process for a deliverability study, which can take two years, may require costly upgrades to the transmission system in order to make the generator fully deliverable. The CAISO is currently conducting a stakeholder process to evaluate alternative paths to deliverability for distributed generation.

20. To ensure ratepayer indifference under § 399.20(d)(3), a market-based approach to pricing is in the best interest of California electricity customers.

21. Section 399.20(f) restricts the Commission from creating program requirements that interfere with the first-come-first-served requirement as it applies to the program as a whole but also permits consideration of a limited type of pricing elements.

22. In the absence of any specific legislative directive, a Commission requirement that pricing be distinguished based on a technology-specific basis would interfere with the application of the statutory provisions requiring first-come-first-served, ratepayer indifference, and cost containment.

23. The statute allows for first-come-first-served on a product specific basis as it specifically directs the Commission to consider the value of different electricity products including baseload, peaking, and as-available electricity in § 399.20(d).

24. This decision implements the statutory amendments by increasing the maximum size of the eligible facility to 3 MW.

25. Additional measures must be implemented to prevent daisy-chaining, i.e., when a project appears to be part of a larger overall installation by the same

company or consortium in the same general location, as daisy-chaining is a means to evade the size restrictions.

26. Unless today's decision modifies the RAM Program, the RAM Program and the FiT Program will overlap for projects 3 MW and under and the potential for gaming of the price of the two programs for projects of 3 MW and under will exist.

27. A means to ensure that only viable projects participate in the FiT Program is required.

28. Increasing the viability of contracts executed pursuant to the FiT Program will allow for more efficient management of the limited program capacity and benefit the market by reducing speculative contracts.

29. Supporting viable projects supports the fifth policy guideline adopted by this decision to increase the probability of successful projects by establishing project viability criteria.

30. The plain language of the statute provides the Commission with authority to modify the program as applied to small electrical corporations in a manner that includes fully removing these utilities from the program. The costs of administering this program for the smaller utilities outweighs any potential benefit from their contribution of approximately 3 MW to the overall program.

31. The plain language of the statute establishes a total cap of 750 MW for the entire § 399.20 Program.

32. Consistency and administrative simplicity will be furthered by retaining the existing allocation methodology for 750 MW, updated in certain respects, adopted by the Commission in D.07-07-027.

33. No statutory provision requires us to consider a set aside, and a set aside program for a particular technology is inconsistent with the requirement that the program be made available on a first-come-first-served basis.

34. PG&E, SCE, and SDG&E maintain two tariff schedules under § 399.20 which are similar in many respects. In the interest of administrative efficiency, no justification exits to retain two separate schedules should no longer be retained.

35. The plain language of § 399.20 establishes that the FiT Program is not limited to retail customers of the electrical corporation but, instead, available to those that are owners or operators of the electric generation facility.

36. The plain language of the statute does not prohibit the sale of excess generation.

37. While the plain language of the statute does not provide definitive direction on the question of reporting frequency, annual reporting, rather than a longer time interval is appropriate because of the importance of proper maintenance of the electric system.

38. Adopting reporting requirements similar to those already included in existing programs, such as the RAM Program implemented by D.10-12-048 and various advice letters, including PG&E's Advice Letter 3809-E, provides efficiencies and transparency. While the statutory language does not require this level of information, it does not prohibit the Commission from requiring such disclosure and is justified by our goal of increased transparency.

39. Administrative ease and reducing transaction costs are achieved by adopting clear policies around when an electric corporation may deny a tariff request; it is also reasonable to place a certain amount of discretion in the utility

to carrying out subsection (n), especially since the denials are subject to a statutorily required appeal process before the Commission.

40. Neither the statutory language itself nor secondary sources further clarify denial of requests under § 399.20(n).

41. The statutory language set forth in § 399.20(l) and the interest of promoting stability of this program suggest that the termination provisions be interpreted narrowly.

42. Expedited interconnection is critical to the success of the § 399.20 FiT Program and is required by statute.

43. SB 32 added subsection (k) to § 399.20 to require owners of eligible generation facilities to refund any incentives received from the CSI or the SGIP before participating in the FiT Program.

44. The Joint Parties filed a motion on December 19, 2011 requesting further consideration of an administratively determined, avoided cost based pricing mechanism and noted their concern that this proceeding had given the Renewable FiT Staff Proposal greater consideration or more evidentiary weight than other pricing proposals because the Staff's Proposal was presented in an ALJ's ruling dated October 13, 2011 and, in addition, discussed at a Staff Workshop on September 26, 2011.

45. The issues framed by Solutions for Utilities' petition for modification have been addressed in different aspects of this proceeding or will be addressed either in this proceeding or in the separate, ongoing Commission rulemaking on Rule 21 interconnection matters, R.11-09-011.

46. The issues framed by Sustainable Conservation's petition for modification are addressed in today's decision or will be addressed in the separate, ongoing rulemaking before the Commission, R.11-09-011.

Conclusions of Law

1. In implementing the amendments to the § 399.20 FiT Program, we rely on federal law, specifically, avoided cost under PURPA, state laws governing statutory construction, and the policy guidelines adopted herein.

2. The modifications to the § 399.20 FiT Program adopted today comply with federal law by requiring, among other things, that all FERC jurisdictional generators participating in the program register with the FERC as QFs and by adopting a price consistent with PURPA, including the most recent guidance provided by FERC regarding avoided costs pricing for QFs on October 21, 2010 in *California Public Utilities Commission* (2010) 133 FERC ¶61,059 (*FERC Clarification Order*).

3. Based on the *FERC Clarification Order*, the Commission can determine a different avoided cost, differentiated for particular sources of energy as long as state law has imposed an obligation on the utility to purchase energy from those sources of energy.

4. The *FERC Clarification Order* increases the pricing options the Commission can consider when determining the § 399.20 FiT Program price.

5. In implementing the statutory amendments to § 399.20, we are guided by, among other things, the rules of statutory construction together with the Commission's fundamental responsibility to oversee the utility's provision of an adequate supply of safe and reliable electricity at just and reasonable rates.

6. Our primary source of guidance in implementing SB 380, SB 32 and SB 2 1X is derived from the rules of statutory construction.

7. Most significantly for purposes of the § 399.20 FiT Program, SB 32 and SB 2 1X provide new direction to the Commission on how to determine the market price for the § 399.20 FiT Program as electricity purchased under § 399.20

is no longer tied to the MPR. As a result, the potential range of pricing outcomes for the § 399.20 FiT Program has expanded.

8. We should adopt five core policy guidelines as an important secondary source of guidance in implementing SB 380, SB 32 and SB 2 1X. These policy guidelines underlie our adoption of a revised § 399.20 FiT Program price and other program elements.

9. Because the MPR is based on a natural gas-fired electric plant, and not a renewable generator, using the MPR to set § 399.20 FiT Program price fails to achieve our first policy guideline: to "establish a feed-in tariff price based on quantifiable utility avoided costs that will stimulate market demand."

10. Because the MPR does not reflect ongoing changes within the renewable market and, as a result, could potentially result in a price either too low or too high, using the MPR to set § 399.20 FiT Program price fails to achieve our first policy guideline: to "establish a feed-in tariff price based on quantifiable utility avoided costs that will stimulate market demand."

11. The renewable market is sufficiently robust to serve as a point of reference for establishing a market price for the § 399.20 FiT Program, and, therefore, we decline to adopt a pricing proposal that relies upon the MPR.

12. Other proposals that incorporate the MPR, such as those proposals by CALSEIA, Placer County, Silverado Power, the Solar Alliance, Vote Solar Initiative, Clean Coalition, and other parties should not be adopted because these proposals fail to recognize that the renewable market is sufficiently robust to more accurately reflect generation costs of the FiT Program as compared to the cost reflected in the MPR, that of a natural gas plant.

13. The methodologies presented to determine certain adders, such as those based on technology specific generation, are largely based on general avoided

societal costs, and not ratepayer or utility costs, which might be argued to be inconsistent with federal requirements under PURPA.

14. Because technology specific adders are largely based on general avoided societal costs, and not ratepayer costs, these adders are inconsistent with three of the policy guidelines adopted by this decision: (1) Establish a feed-in tariff price based on quantifiable utility avoided costs that will stimulate market demand; (2) Contain costs and ensure maximum value to the ratepayer and utility; and (3) Ensure administrative ease and lower transaction costs for the buyer, seller, and regulator.

15. State law does not specifically direct the Commission to account for the unique cost of each technology. The plain language of § 399.20 neither directs nor suggests that technology-specific costs be included in a FiT Program price methodology.

16. Technology-specific pricing is inconsistent with three of the policy guidelines adopted by in this decision: (1) Establish a feed-in tariff price based on quantifiable utility avoided costs; (2) Contain costs and ensure maximum value to the ratepayer and utility; and (3) Ensure administrative ease and lower transaction costs for the buyer, seller, and regulator.

17. Since renewable generators under the § 399.20 FiT Program are required to sign long-term power purchase agreements (a minimum of 10 years per § 399.20), generators under the § 399.20 FiT Program represent a different value than the net surplus compensation from net-energy metered customers and, accordingly, should not be paid the same rate.

18. The net surplus compensation rate is inconsistent with our first policy guideline, to "establish a feed-in tariff price based on quantifiable utility avoided costs that stimulate market demand," since the rate is based on the hourly

day-ahead electricity market price, or DLAP price, and not the market price for renewable electricity.

19. When combined with SCE's adjustment mechanism, using RAM contracts to set the FiT Program starting price is consistent with the three policy guidelines that relate to choosing a FiT price: (1) Establish a feed-in tariff price based on quantifiable utility avoided costs that results in market demand; (2) Contain costs and ensure maximum value to the ratepayer and utility; and (3) Ensure administrative ease and lower transaction costs for the buyer, seller, and regulator.

20. The pricing methodology we adopt today, Re-MAT, complies with both state and federal law.

21. Because the § 399.20 FiT Program seeks to implement a directive from the Legislature to procure energy from specific sources, renewable generation of 3 MW and less, and to consider the value of different electricity products including baseload, peaking, and as-available electricity, we find using RAM contracts to set the § 399.20 FiT Program starting price, which includes these product types, is the most reasonable alternative to determining the cost of the resources being avoided.

22. A starting price for the § 399.20 FiT Program based on the weighted average of PG&E's, SCE's, and SDG&E's highest executed contract resulting from the RAM auction held in November 2011 is reasonable.

23. Based on the November 2011 auction prices and related information, PG&E's recommendation articulated in its November 2011 comments to use a weighted average of the highest executed RAM contract from each IOU to establish a single, statewide FiT price for each of the three product types provides a reasonable starting price for the FiT Program because the price will be

set by the most recent comparable competitive solicitation for renewable distributed generation.

24. It is reasonable to adjust the starting price by time-of-delivery factors based on the generator's actual energy delivery profile to capture the value of each individual generator to the utility.

25. A two-month price adjustment mechanism for each product type should be adopted. The price may increase or decrease from the prior two month's price by increasing or decreasing amounts, depending on the subscription results in each product type for each utility.

26. Each utility should use this adjustment mechanism for each of the three product types.

27. Utilities should be permitted to file a motion to temporarily suspend the program if evidence of market manipulation or malfunction exists.

28. Utilities should incrementally release a portion of their total program capacity allocation each two months for a 24-month period.

29. Utilities should reassign unsubscribed capacity to the same product types starting with Months 25-26 and beyond to prevent gaming, minimize ratepayer exposure to excessively high contract prices, and efficiently manage allocated unsubscribed capacity.

30. To address concerns related to the need and burden of a deliverability study for small distributed generation but, at the same time, ensure compliance with resource adequacy requirements in § 399.20(i), time-of-delivery factors should be adopted for generators that do not provide resource adequacy.

31. The adopted pricing methodology, Re-MAT, is a market-based pricing methodology that reflects the supply and demand of the renewable electricity market to best ensure ratepayer indifference under § 399.20(d)(3).

32. Re-MAT, which includes consideration of product types but not specific technologies, is consistent with the first-come-first-served provision set forth in § 399.20(f) because the statute permits consideration of product types.

33. Increasing the maximum project size to 3 MW is reasonable based on the Commission's obligation to implement provisions of the statute and as reliability concerns, if any, are identified and mitigated during the interconnection process.

34. To prevent daisy-chaining, the utilities should add a provision to the § 399.20 FiT Program standard form contract that requires the seller to attest that the project represents the only project being developed by the seller on any single or contiguous piece of property. This provision should also give utilities the authority to deny a tariff request pursuant to § 399.20(n) if the project appears to be part of a larger overall installation by the same company or consortium in the same general location.

35. To effectively prevent potential gaming, generators with a nameplate capacity of 3 MW and under that meet other eligibility criteria for the FiT Program should be prohibited from participating in the RAM Program if the capacity for the relevant FiT product type has not yet been reached.

36. The statutory language, "strategically located," is interpreted to optimize the deliverability of electricity generated at the FiT project to load centers, which means that a generator must be interconnected to the distribution system, as opposed to the transmission system, and sited near load, meaning in an area where interconnection of the proposed generation to the distribution system requires $300,000 or less of upgrades to the transmission system.

37. To increase the likelihood that projects participating in the FiT Program are viable projects, it is reasonable to adopt project viability criteria similar to those relied upon in the RAM Program.

38. Electric corporations with less than 100,000 service connections should be removed from the § 399.20 FiT Program.

39. The FiT Program cap should be increased to 750 MW and a proportionate share of the 750 MW (with a proportionate share designated for publicly owned utilities) should be allocated to the three largest electric utilities regulated by the Commission. The allocations, made in accordance with the methodology adopted in D.07-07-027, should be as follows: PG&E 218.8 MW; SCE 226 MW; SDG&E 48.8 MW, for a total of 493 MW.

40. In the interest of consistency and administrative simplicity, it is reasonable to retain the existing allocation methodology, updated in certain respects, adopted by the Commission in D.07-07-027.

41. No set-aside (or carve-out) of capacity for specific technologies should be adopted because § 399.20 applies equally to all electric generation facilities, regardless of technology, and must be made available on a first-come-first-served basis under § 399.20(f).

42. Due to the various statutory changes, it is logical for PG&E, SCE, and SDG&E to combine existing tariffs setting forth their § 399.20 FiT Programs into a single tariff for each utility.

43. This decision implements SB 32 by eliminating the requirement that participating generators be retail customers to participate in the § 399.20 FiT Program.

44. The FiT Program should not exclude excess sales.

45. This decision implements SB 32 by directing utilities to add an annual inspection and maintenance provision to the standard contracts under the § 399.20 FiT Program.

46. This decision implements SB 32 by directing utilities to add a 10-day reporting requirement to the standard contracts for the § 399.20 FiT Program. The information required is set forth in Attachment A.

47. This decision implements SB 32 by directing utilities to incorporate a provision into their standard form contracts for written notice of a denial of a request for service under the § 399.20 FiT Program which, at a minimum, requires a denial of service under § 399.20(n) be provided in writing to the producer.

48. This decision implements SB 32 by directing utilities to incorporate a provision into their standard form contracts for termination of service under the § 399.20 FiT Program.

49. This decision implements SB 32 pertaining to expedited interconnection by clarifying that parties should rely on the existing provisions of Tariff Rule 21 (rather than those under review in R.11-09-011) until the Commission finalizes its ongoing efforts to refine Tariff Rule 21 and expedited interconnection in R.11-09-011. Until the Commission makes a final determination in R.11-09-011, utilities should also allow generators to choose which interconnection processes to use, either the process set forth in Tariff Rule 21 or the FERC interconnection procedures.

50. To implement § 399.2(k) requiring refund of CSI and SGIP incentives, a generator that previously received incentives under CSI or SGIP can participate in the § 399.20 FiT Program and will owe no refund if it has been online and operational for at least ten years from the date it first received the incentive. Net-energy metering customers can participate in the § 399.20 FiT Program but should first terminate participation in net-energy metering.

51. A participating generator should register with FERC as a QF. Generators may utilize FERC's self-certification process by filling out FERC's Form 556.

52. The program Rules in place when a contract is executed apply.

53. The Commission gave full consideration to all pricing options presented in the proceeding, including that of an "administratively determined, avoided-cost based pricing mechanism."

54. The petition for modification of D.07-07-027 filed by Solutions for Utilities on June 18, 2010 should be denied.

55. The petition for modification of D.07-07-027 filed by Sustainable Conservation on June 29, 2011 should be denied.

ORDER

1. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall incorporate the starting price for three product types, the adjustment mechanism, and their program capacity allocation, and incremental capacity releases into their tariffs and standard contracts for the § 399.20 Feed-in Tariff (FiT) Program being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 Administrative Law Judge ruling. The Commission will review these provisions and, in a separate decision accept, reject, or modify the provisions. Related FiT tariff modifications will also be addressed in this separate decision.

2. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall make the Feed-in Tariff price and available capacity, including any results from the price adjustment mechanism or the capacity reassignment methodology, continuously available to the public on their websites by the first business day of each two-month period.

3. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall convene stakeholders within the first year of the § 399.20 Feed-in Tariff Program to solicit market experience with the pricing adjustment mechanism. PG&E, SCE, and SDG&E shall also establish an online mechanism for continuous receipt of public input on the program. To the extent that changes to the price adjustment, capacity allocation mechanism, or other aspects of the program are needed to improve the program, PG&E, SCE, and SDG&E are permitted to file a joint Advice Letter seeking specific changes.

4. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall offer two sets of time-of-delivery factors: one for generators that do not provide resource adequacy and another for generators that do provide resource adequacy. PG&E, SCE, and SDG&E shall add a provision reflecting delivery factors to the § 399.20 Feed-in Tariff (FiT) Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 Administrative Law Judge ruling. The Commission will review this provision and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

5. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall add a provision reflecting the increase in eligible generator projects to three megawatts to the § 399.20 Feed-in Tariff (FiT) Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 Administrative Law Judge ruling. The Commission will review

this provision and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

6. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall add a provision to the § 399.20 Feed-in Tariff (FiT) Program standard form contract and/or tariff that requires the seller to attest that the project represents the only project being developed by the seller on any single or contiguous piece of property. This provision will give PG&E, SCE and SDG&E the authority to deny a tariff request pursuant to § 399.20(n) if the project appears to be part of a larger overall installation by the same company or consortium in the same general location. This provision shall permit generators to contest a denial under § 399.20(n) through the Commission's standard complaint procedure set forth the Commission's Rules of Practice and Procedure. The Commission will review this provision and, in a separate decision, accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

7. Within 90 days of the effective date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall file a Tier 1 Advice Letter restricting Renewable Auction Mechanism (RAM) to generators with a nameplate capacity of greater than three megawatts and that do not satisfy the Feed-in Tariff eligibility criteria. This change will not affect the upcoming RAM auction scheduled to close in May 2012 but will take effect in time for the third RAM auction scheduled for the end of 2012.

8. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall add a provision to the § 399.20 Feed-in Tariff (FiT) Program standard form contract and/or tariff addressing the

prerequisite that generators must be "strategically located." This means that the generator be (1) interconnected to the distribution system, as opposed to the transmission system, and (2) sited near load, meaning sited in an area where interconnection of the proposed generation requires $300,000 or less of upgrades to the transmission system. Such a provision shall be presented to the Commission for consideration in accordance with the schedule set forth in January 10, 2012 ALJ ruling. The Commission will review this provision and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

9. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall add a provision reflecting the adopted project viability criteria to the § 399.20 Feed-in Tariff (FiT) Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 Administrative Law Judge ruling. The Commission will review this provision and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

10. Within 90 days of the effective date of this decision and pursuant to § 399.20(c), electrical corporations with less than 100,000 service connections within this state shall file Tier 1 Advice Letters withdrawing their tariffs relevant to the § 399.20 Feed-in Tariff Program.

11. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall modify tariff and/or contract provisions to reflect the consolidation of tariffs applicable to public water or wastewater agencies and tariffs for other customers in the § 399.20 Feed-in Tariff (FiT) Program. These modifications shall be incorporated into the standard form

contract that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review these provisions and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

12. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall remove, as necessary, references to retail customers in the Feed-in Tariff (FiT) Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. PG&E, SCE, and SDG&E are required to offer generators two options: either full sales or excess sales. The nameplate capacity of all generators participating in this program is limited to three megawatts, regardless of the sales option. The Commission will review this provision submitted by the utilities and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

13. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall add a provision reflecting the annual inspection and maintenance reporting to the § 399.20 Feed-in Tariff (FiT) Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 Administrative Law Judge ruling. The Commission will review this provision and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

14. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall add a provision reflecting the

10-day reporting requirement for requests for service in the § 399.20 Feed-in Tariff (FiT) Program standard form contract and/or tariff being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 Administrative Law Judge ruling. The Commission will review this provision and, in a separate decision accept, reject, or modify the provision. Related FiT Tariff modifications will also be addressed in this separate decision.

15. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall add a provision regarding denial of service by the utility to the § 399.20 Feed-in Tariff (FiT) Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 Administrative Law Judge ruling. The Commission will review this provision and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

16. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall add a provision reflecting contract termination to the § 399.20 Feed-in Tariff (FiT) Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 Administrative Law Judge ruling. Other termination provisions may be included in the standard form contract. The Commission will review this provision and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

17. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall add a provision reflecting the eligibility to participate in the § 399.20 Feed-in Tariff (Fit) Program based on past

participation and receipt of California Solar Initiative and Small Generator Incentive Program incentives in the § 399.20 FiT Program standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 Administrative Law Judge ruling. The Commission will review this provision and, in a separate decision accept, reject, or modify the provision. Related FiT tariff modifications will also be addressed in this separate decision.

18. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall be authorized to file a motion to temporarily suspend the Section 399.20 Feed-in Tariff Program when evidence of market manipulation or malfunction exists. The motion shall be served on the service list of this proceeding or any successor proceeding. This authorization shall be incorporated into the standard form contract and/or tariff that is being developed in this proceeding in accordance with the schedule set forth in the January 10, 2012 ALJ ruling. The Commission will review this provision and, in a separate decision accept, reject, or modify the provision.

19. The Joint Motion of the Center for Energy Efficiency and Renewable Technologies; AG Power Group, LLC; Sustainable Conservation; Agricultural Energy Consumers Association; Green Power Institute; California Wastewater Climate Change Group; California Farm Bureau Federation; Fuel Cell Energy; and FlexEnergy, Inc., for a Ruling Directing the Consideration of an Administratively determined Avoided Cost Pricing Methodology for the Renewable FIT at a January 2012 Workshop that Would be Part of the Record for the Decision on the Renewable FIT filed on December 19, 2011 is denied.

20. The Petition for Modification of D.07-07-027 filed by Solutions for Utilities on June 18, 2010 is denied.

21. The Petition for Modification of D.07-07-027 filed by Sustainable Conservation on June 29, 2011 is denied.

22. Rulemaking 11-05-005 remains open.

The order is effective today.

Dated May 24, 2012, in San Francisco, California.

MICHAEL R. PEEVEY
President
TIMOTHY ALAN SIMON
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
MARK J. FERRON
Commissioners

Attachment A - 10-day reporting requirement to tariffs under the § 399.20 FiT Program R.11-05-005

Link to Pro Forma FiT PPA until actual PPA is public.

Because of small size of FiT projects, include capacity to two decimal places.

A	B	C	D	E	F	G	H	I	J	K	L
Contract Effective Date	Seller Name and Project Name	FiT PPA	Status (On-Schedule, Delayed, Operational, Terminated)	IOU	Contract Capacity (MW)	Expected Generation (GWh/yr)	Technology	Vintage	Contract Term (years)	Location (city and county)	Contracted Commercial Operation Date (COD)
7/15/12	AES Delano	Download	Operational	SDG&E	1.50	34	Solar PV	existing	10	Delano, Kern County	01/01/13
			Terminated	PG&E			Wind	new	15		
			Delayed	SDG&E			Geothermal		20		
			On-Schedule				Biogas				
							Biomass				
							Small hydro				
							Solar Thermal				
							Landfill Gas				
							Wave				
							Tidal				

NOTE: Columns shaded in red are new fields added specifically for Feed in Tariff projects. Columns N [6-month Regulatory Delay] through R [Stage in Interconnection Process] should be updated twice yearly concurrent with other existing RPS reporting requirements.

M	N	O	P	Q	R	S	T	U
Actual Commercial Operation Date (COD)	6-month Regulatory Delay (Y/N)	Reason for Regulatory Delay (Site, Permit, Interconnection, Transmission)	Interconnection Agreement Signed (Y/N)	Interconnection Agreement Application Completed (Y/N)	Stage in Interconnection Process (Study, Agreement, Construction, Completion)	Full Buy/Sell or Excess Sales	Product Category (Baseload, peaking intermittent, non-peaking intermittent)	Full Capacity Deliverability Status (FCDS) or Energy-Only
1/15/2013	N	-	Y	Y	Completion	Full Buy/Sell	Baseload	FCDS
	Y	Site	N	N	Agreement	Excess Sale	Peaking intermittent	Energy-only
	Y	Permit			Construction		Non-Peaking intermittent	
	Y	Interconnection			Feasibility Study			
		Transmission			System Impact Study			
					Facilities Study			
					Fast Track			
					Supplemental Review			
					Simplified Review			
					Cluster Study Phase I			
					Cluster Study Phase II			

(End of Attachment A)

EXHIBIT B

L/ice

Date of Issuance
January 28, 2013

Decision 13-01-041 January 24, 2013

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	Rulemaking 11-05-005 (Filed May 5, 2011)

ORDER MODIFYING DECISION (D.) 12-05-035, AND DENYING REHEARING OF DECISION, AS MODIFIED

I. INTRODUCTION

In Decision (D.) 12-05-035 (or "Decision"), we implemented amendments to Public Utilities Code section 399.20.[1] The Decision adopted a new pricing mechanism and other new or revised components for the Feed-in Tariff ("FiT") program under section 399.20. The Decision refers to the new program resulting from these revisions to the FiT as the Renewable Market Adjusting Tariff ("Re-MAT"). The Decision also denied two petitions for modification of *Opinion Adopting Tariffs and Standard Contracts for Water, Wastewater and Other Customers to Sell Electricity Generated from RPS-Eligible Renewable Resources to Electrical Corporations* [D.07-07-027](2007) __ Cal.P.U.C.3d __, the decision that initially established the tariffs and standard contracts for the investor-owned utilities ("IOUs") under section 399.20.

Applications for rehearing of D.12-05-035 were timely filed by the Center for Energy Efficiency and Renewable Technologies ("CEERT"); Placer County Air Pollution Control District ("District"); Sustainable Conservation; CAlifornians for

[1] All subsequent section references are to the Public Utilities Code unless otherwise specified.

Renewable Energy, Inc. ("CARE"); and jointly by the Clean Coalition and Sierra Club California (collectively, "Clean Coalition/Sierra Club").

CEERT alleges that the Decision violates section 399.20 by: (1) adopting a pricing mechanism that does not incorporate "environmental compliance costs;" (2) failing to demonstrate that a pricing mechanism based on the Renewable Auction Mechanism ("RAM") will attract the projects and technology types the Legislature intended to target through section 399.20; and (3) limiting the overall program size to 750 MW, which includes the existing 250 MW in the Assembly Bill 1969 (Stats. 2006, ch. 731) ("AB 1969") program that were executed pursuant to the program established under D.07-07-027.

The District requests that the Commission grant rehearing on the issue of whether or not existing contracts executed under the FiT established by D.07-07-027 should be included in the new 750 MW cap implemented by the Decision. The District's rehearing application relies on a motion it filed requesting that the Commission reopen the record in order to take official notice of the existing less than 3 MW contracts that are for facilities in the IOUs' service territories.

Sustainable Conservation alleges the following errors: (1) the Decision violates Senate Bill 32's (Stats. 2009, ch. 328) ("SB 32") mandates concerning environmental compliance costs; (2) the Decision adopted an inappropriate pricing benchmark that is not based on comparable relevant resources; and (3) the Decision renders the FiT program inaccessible to certain technology types, particularly baseload projects.

CARE alleges the Decision fails to comply with the Public Utility Regulatory Policies Act of 1978 ("PURPA") and the regulations and orders of the Federal Energy Regulatory Commission ("FERC") by, among other things: (1) failing to adopt technology specific pricing; (2) adopting a price based on the RAM; (3) using a weighted average of the utilities' data to determine a single FiT starting price; and (4) adopting a price adjustment mechanism. CARE also alleges numerous other factual and legal errors, including: (1) the Decision does not accurately cite all the sections of

PURPA; (2) the Decision erroneously states it uses the FERC's most recent guidance on avoided cost pricing; (3) the Decision errs by requiring utilities to file a motion to temporarily suspend the program where there is evidence of market manipulation; (4) the Energy Division's approval of recent advice letters based on the first RAM solicitation violates General Order ("GO") 96-B; and (5) the Decision finds that additional measures must be taken to prevent daisy-chaining but the Commission has a history of approving daisy chaining contracts. CARE also alleges that the filing of its rehearing application stays the Decision for at least 60 days.

Clean Coalition/Sierra Club allege the following errors: (1) the Decision violates SB 32's requirement to provide a price for avoided transmission and distribution costs; (2) the Decision violates SB 32's requirement to provide compensation for mitigation of local environmental compliance costs; (3) the Decision is contradictory regarding whether the FiT program can be quickly subscribed; (4) the requirement that projects may not incur transmission upgrade expenses over $300,000 eliminates a substantial portion of potential SB 32 projects; (5) the Decision erroneously suggests that developers can use the IOU interconnection maps to determine whether a project is likely to have transmission impacts; (6) the Decision fails to provide sufficient clarity in prescribing allocation of capacity; and (7) the Decision fails to clarify whether the program under AB 1969 is suspended. Clean Coalition/Sierra Club also allege that the Decision contains numerous typographical and grammatical errors that may cause confusion in implementation.[2]

Southern California Edison Company ("Edison") and Pacific Gas and Electric Company ("PG&E") jointly filed two responses to the rehearing applications: one response to CARE's rehearing application ("Resp. to CARE Rehrg. App.") and one

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[2] Clean Coalition/Sierra Club's citations to the Decision are inaccurate throughout their rehearing application as they do not correspond to the official slip opinion of the Decision issued by the Commission.

response to the rehearing applications filed by CEERT, the District, Clean Coalition/Sierra Club, and Sustainable Conservation ("Resp. to Rehrg. Apps.").

We have reviewed each and every argument raised in the rehearing applications and are of the opinion that modifications, as described herein, are warranted to: (1) explain that the adopted pricing mechanism should account for all of the generator's costs, including environmental compliance costs; (2) delete the statement that the Commission seeks to pay generators the price needed to build and operate a renewable generation facility; (3) delete statements that imply that avoided costs under PURPA are based in part on avoided ratepayer costs; (4) correct statements regarding section 399.20(f)'s requirement that the tariff be available on a "first-come-first-served basis;" (5) clarify the reasons for declining to adopt a location or transmission adder; (6) delete the statement that the FiT program may be quickly subscribed; (7) clarify how the program's capacity is allocated and incrementally released; (8) delete statements that the Market Price Referent ("MPR") is based on a "market;" (9) clarify statements regarding the legal requirements for setting avoided cost and the holdings of *California Public Utilities Commission* ("*FERC Clarification Order*") (2010) 133 FERC ¶ 61,059; (10) correct the statement that subscription in a two-month period can equal more than 100% of the initial capacity allocation for a product type; and (11) correct typographical errors. As modified, rehearing of D.12-05-035 is denied. We also reject the District's rehearing application for failing to meet the requirements of section 1732.

II. DISCUSSION

A. Allegation that the Decision erred by not including environmental compliance costs in the Re-MAT price

CEERT, Sustainable Conservation, and Clean Coalition/Sierra Club allege that the Decision fails to include environmental compliance costs in the Re-MAT price, and thus, fails to comply with SB 32 and the requirements of section 399.20 that the payment pursuant to the standard tariff "shall include all current and anticipated

environmental compliance costs." (CEERT Rehrg. App., pp. 8-12; Sustainable Conservation Rehrg. App., p. 3-5; Clean Coalition/Sierra Club Rehrg. App., p. 7.)[3]

SB 32 states that among other things: "a tariff for electricity generated by renewable technologies should recognize the environmental attributes of the renewable technology." (Sen. Bill No. 32 (Stats. 2009, ch. 328) § 1, subd. (e).) Section 399.20(d)(1) provides that the payment pursuant to the standard tariff:

> shall include all current and anticipated environmental compliance costs, including, but not limited to, mitigation of emissions of greenhouse gases and air pollution offsets associated with the operation of new generating facilities in the local air pollution control or air quality management district where the electric generation facility is located.

The Re-MAT uses the RAM as a starting price with the price for each product type increasing or decreasing via a price adjustment mechanism to respond to market conditions. The Decision determined that the general costs associated with producing renewable energy were embedded in the starting price of the RAM but that specific costs, such as the compliance costs in a particular air quality management district, were not necessarily captured by the RAM pricing methodology. (D.12-05-035, pp. 42 & 53.) The Decision declined to adopt an adder for environmental compliance costs. The Decision found that there was insufficient information in the record to adopt an adder for environmental compliance costs, but stated that it would prioritize and resolve this issue at a later date. (D.12-05-035, p. 54.)

In their response to the rehearing applications, Edison and PG&E assert that environmental compliance costs are accounted for via the Re-MAT price adjustment

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[3] CEERT's rehearing application conflates "environmental adders" reflecting certain environmental attributes with "environmental compliance costs." (See CEERT Rehrg. App., pp. 9-10.) As explained in the Decision, these are two distinct types of costs. (D.12-05-035, p. 51.) To the extent CEERT is alleging that the Commission erred in declining to adopt specific environmental adders to account for the environmental benefits produced by certain renewable technologies, CEERT fails to demonstrate any legal error. As explained in Section II.B., below, the general costs associated with producing renewable energy are accounted for in the Re-MAT price and there is no legal requirement for any technology-specific adder.

mechanism. (Resp. to Rehrg. Apps., p. 2.) According to Edison and PG&E, under the Re-MAT, generators will strike on the available price that covers their project costs, including environmental compliance costs, plus a reasonable rate of return. (Resp. to Rehrg. Apps., pp. 2-3.)

Indeed, the rationale for a market-based price is that all of the generator's costs are included in the price because a generator would not bid something lower than its costs. In a market-based process, the seller determines the price it wishes to seek based on its understanding of the underlying project costs, and changes in those costs. (*Decision Adopting the Renewable Auction Mechanism* [D.10-12-048] (2010) __ Cal.P.U.C.3d __, p. 17 (slip op.).) In adopting the RAM, we found that a rational bidder would include all of its costs in its bid. (*Id*. at p. 85 [Finding of Fact ("FOF") 36].)

Given that all costs incurred by a generator are presumed included in a market-based price, we see no reason why environmental compliance costs should be treated differently from any other costs incurred by a generator. A generator should include all of its costs, including any environmental compliance costs, in its price for the Re-MAT. The Re-MAT price adjusts based on market conditions and demand and, thus, should account for these costs. (See also, *Southern California Edison Company's Comments to Section 399.20 Ruling dated June 27, 2011*, dated July 21, 2011, p. 4 [market-based process would allow current and anticipated environmental costs to be included in the price]; *Clean Coalition Reply Comments on ALJ Ruling*, dated August 26, 2011, p. 31 [price adjustment mechanism could result in a price that includes environmental compliance costs].) Therefore, we modify the Decision, as set forth in the ordering paragraphs below, to explain that because the Re-MAT is a market-based price, it should include all of the generator's costs, including current and anticipated environmental compliance costs.

In discussing the issue of environmental compliance costs, the Decision also stated that "[w]e seek to pay generators the price needed to build and operate a renewable generation facility." (D.12-05-035, p. 42.) Clean Coalition/Sierra Club claim that this language violates SB 32 and is nowhere in the law. (Clean Coalition/Sierra Club

Rehrg. App., p. 7.) Clean Coalition/Sierra Club do not specify what provisions of SB 32 this language would violate. But we agree that there is no legal requirement that these costs be recovered and we modify the Decision, as set forth in the ordering paragraphs below, to delete this unnecessary statement. (See Pub. Util. Code, § 399.20, subd. (d)(2).)

B. Allegations that the FiT should be based on technology-specific pricing with set asides for specific technologies

Sustainable Conservation and CEERT allege that the Commission erred in basing the Re-MAT price on the RAM.[4] Sustainable Conservation asserts that the RAM is not a relevant benchmark because it is for projects up to 20 MW whereas the Re-MAT is for small renewable projects up to 3 MW. (Sustainable Conservation Rehrg. App., pp. 5-6.) According to Sustainable Conservation, less than 2% of projects that bid into the November 2011 RAM auction were from baseload technologies. (Sustainable Conservation Rehrg. App., p. 6.) Relying on the analysis of Fuel Cell Energy, Inc. ("Fuel Cell"), Sustainable Conservation asserts that the Commission should develop an auction for each technology type. (Sustainable Conservation Rehrg. App., p. 7)

CEERT alleges that the Decision failed to explain how a pricing mechanism based on the RAM will attract the projects and technology types the Legislature intended to target through section 399.20. According to CEERT, the November 2011 RAM solicitation only yielded solar PV and was not technology-neutral. (CEERT Rehrg. App., p. 7.)

The purpose of a rehearing application is to alert the Commission to legal error. A rehearing application must set forth specifically the grounds on which the applicant considers the decision to be unlawful. (Pub. Util. Code, § 1732; Code of Regs., tit. 20, § 16.1, subd. (c).) The purpose of a rehearing application is not to re-litigate policy determinations. (See Pub. Util. Code, § 1732; Code of Regs., tit. 20, § 16.1, subd. (c).)

[4] CARE also makes allegations that the Commission erred in basing the Re-MAT price on the RAM based on federal law. These allegations are addressed in Section II.E.5., below.

Sustainable Conservation and CEERT fail to demonstrate that the pricing methodology adopted in the Decision violates any law. The rehearing applications do not identify a legal requirement that the Commission establish technology-specific pricing or ensure that the FiT attract any specific type of technology other than generation from eligible renewable energy resources.

The Legislature stated its intent to encourage electrical generation from eligible renewable energy resources that meet certain criteria, including having an effective capacity of not more than 3 MW, and being strategically located. (Pub. Util. Code, § 399.20, subds. (a) & (b).) Section 399.20 requires the Commission to "establish a methodology to determine the market price of electricity" for the FiT. (Pub. Util. Code, § 399.20, subd. (d)(2).) In establishing a methodology for the FiT price, the statute requires the Commission to take into account, among other things, the value of different electricity products including baseload, peaking, and as-available electricity. (Pub. Util. Code, § 399.20, subd. (d)(2).) But the statute does not require the Commission to take into account the value of any specific technology type.[5] Subject to express statutory requirements, we have the discretion to determine how the FiT will be implemented. (See Pub. Util. Code, §§ 399.20, subd. (d) & 701; *Consumer Lobby Against Monopolies v. Public Utilities Com.* (1979) 25 Cal.3d 891, 905-906.) Sustainable Conservation relies on Fuel Cell's analysis but Fuel Cell itself acknowledged that "[i]t is clear that there is more than one way the Commission can calculate a price for SB 32 resources." (*Fuel Cell Energy, Inc. Comments to Sec. 399.20 Ruling of June 27, 2011*, dated July 21, 2011, p. 3.)

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[5] Subsequent to the issuance of the Decision, the Legislature enacted Senate Bill 1122 (Stats. 2012, ch. 612) ("SB 1122"), which amended section 399.20 to require electrical corporations to "collectively procure at least 250 megawatts of cumulative rated generating capacity from developers of bioenergy projects that commence operation on or after June 1, 2013." SB 1122 was enacted on September 27, 2012 and is effective as of January 1, 2013. (See Gov. Code, § 9600.) We will be instituting proceedings to implement SB 1122. This order, and any modifications to the Decision made in this order, are based on the statutory requirements that were in place at the time of the issuance of the Decision.

The Decision found that a FiT price based on the results of the November 2011 RAM auction, coupled with an adjustment mechanism, best reflected the market price of generation from eligible renewable energy resources, and was consistent with state and federal law, as well as policy objectives. (D.12-05-035, pp. 118 [Conclusions of Law ("COLs") 19-21] & 119 [COL 31].) Sustainable Conservation and CEERT do not demonstrate that there is any legal error in these determinations. We determined that a starting price based on the RAM was reasonable because the RAM price is based on the market price of renewable energy. (D.12-05-035, p. 118 [COL 21].) We found that the renewable market has evolved since we established the MPR at the beginning of the Renewable Portfolio Standard ("RPS") program and that the renewable market was now sufficiently robust to serve as the point of reference for establishing the market price for small renewable projects. (D.12-05-035, p. 109 [FOFs 4 & 5]; see, e.g., *Southern California Edison Company's Reply Comments to Section 399.20 Ruling dated June 27, 2011*, dated August 26, 2011, p. 10; *The Division of Ratepayer Advocates' Comments to Section 399.20 Ruling Issued June 27, 2011*, dated July 21, 2011, p. 4.)

Sustainable Conservation and CEERT's allegations also fail to take into account the fact that the RAM price is only the starting point for the Re-MAT price. We recognized that the market segments covered by the RAM and section 399.20 are not identical. (D.12-05-035, pp. 39-40.) The RAM covers renewable projects sized up to 20 MW whereas the section 399.20 FiT Program covers renewable projects sized up to 3 MW. For that reason, we adopted a price adjustment mechanism to increase or decrease the FiT price for the three product types based on market conditions.[6] The Decision also provided for the starting price to be adjusted by time-of-delivery factors. Furthermore, although the Decision did not adopt set asides for specific technologies, the Decision did

[6] CEERT claims that the price adjustment mechanism conflicts with the law. (CEERT Rehrg. App., p. 10.) But CEERT does not specify what law or provide any support for this allegation. Thus, CEERT does not demonstrate a basis for legal error with regard to this issue. (See Pub. Util. Code, § 1732, Cal. Code Regs., tit. 20, § 16.1, subd. (c).)

require that the utilities allocate an equal portion of their assigned capacity to the three product types. (D.12-05-35, p. 49.)

As explained in the Decision, we had many reasons for rejecting technology-specific pricing or adders, and for declining to adopt set asides for any specific technologies. We found adders for specific technology types and technology-specific pricing to be inconsistent with the following policy guidelines for the FiT program: (1) establish a feed-in tariff price based on quantifiable utility avoided costs that will stimulate market demand; (2) contain costs and ensure maximum value to the ratepayer and utility; and (3) ensure administrative ease and lower transaction costs for the buyer, seller, and regulator. (D.12-05-035, pp. 33, 34-35.) We determined that environmental adders for specific technologies were not consistent with the ratepayer indifference requirement in section 399.20(d)(4) and the goals of cost containment within the RPS Program. (D.12-05-035, p. 52; see also Pub. Util. Code, §§ 399.15, subds. (c) & (d), 399.20, subd. (d)(4).) The Decision also found that the methodologies used to calculate various technology-specific adders were not based on the utilities' avoided costs, and therefore, would not be the type of "avoided costs" permitted under PURPA.[7] (D.12-05-035, p. 32; see also 18 C.F.R. § 292.304, subd. (a)(2).)

We also declined to adopt these program requirements in part because we interpreted the provision in section 399.20(f) that the tariff be available on a "first-come-first-served basis" as restricting the Commission from adopting these program requirements. (D.12-05-035, pp. 62, 81, 111 [FOFs 21 & 22].) Upon revisiting this issue, we find that the statute does not restrict the Commission from adopting program requirements for the FiT Program.

Section 399.20(f) provides that "[a]n electrical corporation shall make the tariff available … on a first-come-first-served basis." This section discusses the

[7] The Decision also implied that avoided costs under PURPA are based in part on avoided ratepayer costs. (D.12-05-035, pp. 32-33.) Avoided costs under PURPA are based on utilities' avoided costs. (18 C.F.R. § 292.304, subd. (a)(2).) We modify the Decision to delete any statements that imply otherwise.

obligation of the utilities, and does not discuss the Commission's authority to impose program requirements.

The Commission has broad authority over public utilities, including authority over the utilities' resource portfolios and procurement planning, and in implementing the RPS Program. (See, e.g., Cal. Const., art. XII, § 6; Pub. Util. Code, §§ 399.11 et seq., 454.5, 701.) The Commission has the authority to act even in cases where there is no express statutory authorization so long as the additional power and jurisdiction the Commission exercises are cognate and germane to the regulation of public utilities, and do not contravene or disregard an express legislative directive. (Pub. Util. Code, § 701; *Consumer Lobby Against Monopolies v. Public Utilities Com.*, *supra*, 25 Cal.3d at pp. 905-906; *Assembly v. Public Utilities Com.* (1995) 12 Cal. 4th 87, 103.)

Based on the foregoing, we modify the Decision, as set forth in the ordering paragraphs below, to delete any language that suggests that section 399.20(f) restricts the Commission's authority. As explained above, the Commission is not restricted from adopting program requirements for the FiT so long as the imposition of these requirements does not contravene other statutory requirements. To the extent that the Commission imposes program requirements for the FiT, the electrical corporations would comply with section 399.20(f) by incorporating these program requirements into their tariffs, which would be offered on a first-come-first-served basis pursuant to section 399.20(f).

As modified, we deny rehearing as CEERT and Sustainable Conservation have failed to demonstrate any legal error regarding the Decision's determination to reject technology-specific pricing, adders, or set-asides for the FiT for the other reasons stated above.

C. Allegation that the Decision erred in adopting a 750 MW program cap

The Decision set a statewide program capacity cap of 750 MW. The Decision determined that this cap applied to the IOUs and publicly owned utilities. The Decision also determined that capacity under contract in the existing AB 1969 program

would be included in the cap. (D.12-05-035, pp. 74-77.) CEERT argues that the Decision does not examine the impact of setting a 750 MW program cap, and allocating some of the program capacity to existing AB 1969 FiT projects and to the publicly owned utilities. (CEERT Rehrg. App., pp. 7-8, 13.)

CEERT fails to demonstrate any legal error on this issue. The program cap adopted in the Decision is consistent with the statutory requirement that an electrical corporation make the tariff available until it meets its proportionate share of "a statewide cap of 750 megawatts *cumulative* rated generation capacity served under [section 399.20] and section 387.6." (Pub. Util. Code, § 399.20, subd. (f), emphasis added.)[8] The current 3 MW FiT Program superseded and modified the existing AB 1969 program. AB 1969 projects are also served under section 399.20 and, thus, subject to the 750 MW cumulative cap. This cumulative cap also applies to projects under section 387.6. Section 387.6 requires local publicly owned utilities to adopt a standard tariff for electricity purchased from eligible renewable energy resources. Based on the foregoing, there is no legal error in adopting a 750 MW program cap, in including the AB 1969 contracts in the cap, and in allocating some of program capacity to the publicly owned utilities. To the extent that CEERT is attempting to relitigate the policy implications of this cap, this does not constitute a basis for granting rehearing. (Pub. Util. Code, § 1732; Code of Regs., tit. 20, § 16.1, subd. (c).)

D. Other Allegations in Clean Coalition/Sierra Club's Rehearing Application

1. Allegation that the Decision violates SB 32's requirement to provide a price for avoided transmission and distribution costs

SB 32 states:

> A tariff for electricity generated by renewable technologies should recognize the environmental attributes of the

[8] As noted in footnote 5, above, SB 1122 recently amended section 399.20 to increase the program cap by an additional 250 MW for bioenergy projects.

> technology, the characteristics that contribute to peak electricity demand reduction, reduced transmission congestion, avoided transmission and distribution improvements, and in a manner that accelerates the deployment of renewable energy resources.

(Senate Bill 32, Stats. 2009, ch. 328, § 1, subd. (e).) Clean Coalition/Sierra Club allege that the Decision violates this provision of SB 32 by failing to adopt a location or transmission adder. (Clean Coalition/Sierra Club Rehrg. App., pp. 5-6.) This allegation lacks merit.

The price requirements for the tariff are set forth in section 399.20(d). Payment under the FiT shall be "the market price determined by the [C]ommission…." (Pub. Util. Code, § 399.20, subd. (d)(1).) The statute requires the Commission to consider various factors in establishing a pricing methodology for the FiT, but does not specifically require that avoided transmission and distribution costs be included in the FiT price. Clean Coalition/Sierra Club claim that these costs are required to be included in the price based on section 1, subdivision (e) of SB 32, but this subdivision does not dictate pricing requirements for the FiT. With regard to avoided transmission and distribution improvements, this subdivision merely evinces the Legislature's intent that the tariff recognize "the characteristics that contribute to … avoided transmission and distribution improvements." The Decision's implementation of the requirement that projects be "strategically located" goes to this intent. (D.12-05-035, pp. 38, 56-59.)

Assuming arguendo that any law required that avoided transmission and distribution improvements be included in the FiT price, Clean Coalition/Sierra Club still fail to demonstrate that the Decision erred in declining to adopt a location or transmission adder. Any location or transmission adder must be based on costs that are found to be actually avoided by the utilities. (18 C.F.R. § 292.304, subd. (a)(2); *FERC Clarification Order*, *supra*, 133 FERC ¶ 61,059, at P 31.) In this case, the Decision found that the record did not support a finding that the location and transmission adders proposed during the proceeding represented actual costs that would be avoided by the utilities. (D.12-05-035, pp. 37-38; see, e.g., *Southern California Edison Company's Reply*

Comments on the October 13, 2011 Renewable FIT Staff Proposal, dated November 14, 2011, pp. 12-13; *Pacific Gas and Electric Company's Comments on Staff Proposal Regarding the Implementation of Section 399.20*, dated November 2, 2011, pp. 17-19.)

The Decision stated that a location or transmission adder are "either inconsistent with existing law or require more development" and that "additional scrutiny is needed before the Commission adopts a location adder." (D.12-05-035, pp. 37-38.) In order to eliminate any confusion, we modify the Decision, as set forth in the ordering paragraphs below, to clarify that we declined to adopt these adders because we did not find that they were warranted based on the record of this proceeding. This does not foreclose the possibility that a location or transmission adder may be adopted for the program in the future if these adders are found to reflect costs actually avoided by the utilities.

2. Allegation that the Decision is contradictory regarding whether the FiT program can be quickly subscribed

The Decision directed the utilities to incrementally release a portion of their total program capacity allocation every two months for a 24-month period. (D.12-05-035, p. 119 [COL 28].) The Decision also stated: "We are sensitive, however, to the fact that the program's MW may quickly be subscribed. In that situation, we will consider proposals from parties to expand the program." (D.12-05-035, p. 76.)

Clean Coalition/Sierra Club assert that the Decision contradicts itself when it suggests the FiT Program may be expanded if the program's capacity is quickly subscribed because it is not possible to fully subscribe the program before 24 months have run. (Clean Coalition/Sierra Club Rehrg. App., p. 8.)

Clean Coalition/Sierra Club fail to identify any legal error. Thus, there is no basis for rehearing. (Pub. Util. Code, § 1732; Cal. Code Regs., tit. 20, § 16.1, subd. (c).) Although there is no demonstration of legal error, we acknowledge that the statement that the program may be quickly subscribed may be confusing in light of the

directive that the utilities incrementally release their allocated capacity over a 24-month period. Therefore, we modify the Decision to delete this unnecessary statement.

3. Allegation that the Decision erred in requiring that any transmission upgrade expenses may not exceed $300,000

The Decision determined that in order for a generation facility to be considered "strategically located" pursuant to section 399.20(b), a generator must be interconnected to the distribution system, and the project must not require more than $300,000 of transmission system network upgrades. (D.12-05-035, p. 58.) Clean Coalition/Sierra Club allege that the requirement that the project must not require more than $300,000 of transmission system network upgrades may eliminate a substantial portion of potential SB 32 projects. (Clean Coalition/Sierra Club Rehrg. App., p. 9.)

Clean Coalition/Sierra Club do not allege any legal error regarding this issue. Assuming arguendo that this program requirement may eliminate some potential projects, Clean Coalition/Sierra Club do not explain what law would be violated. Thus, rehearing is not warranted. (Pub. Util. Code, § 1732; Cal. Code Regs., tit. 20, § 16.1, subd. (c).) We, in fact, imposed the requirement that a project not exceed more than $300,000 of transmission system network upgrades in order to implement the statutory requirement that a general facility be "strategically located." (See Pub. Util. Code, § 399.20, subd. (b)(3).)

Moreover, Clean Coalition/Sierra Club's allegations are vague and speculative. Their rehearing application alleges that "in certain circumstances" the expense allowance will be exceeded and that the IOU requirement "may eliminate a substantial portion of potential SB 32 projects." (Clean Coalition/Sierra Club Rehrg. App., p. 9.) Clean Coalition/Sierra Club do not cite to any evidence in the record in support of their allegations. A rehearing must make specific references to the record or law. (Cal. Code Regs., tit. 20, § 16.1, subd. (c).) As support for their allegations, Clean Coalition/Sierra Club cite to an attached appendix with what is purportedly a discussion Clean Coalition had with PG&E. (Clean Coalition/Sierra Club Rehrg. App., p. 9.) But

we cannot consider this discussion in disposing of the rehearing application as it was not a part of the record of this proceeding.

4. Allegation that the Decision erred in requiring use of the utilities' interconnection maps

The Decision stated that it expects generators to use the utilities' interconnection maps to locate sites that have a low likelihood of transmission impacts. (D.12-05-035, pp. 58-59.) We have required the utilities to provide these maps to assist projects to locate in preferred locations for the RAM program. (D.10-12-048, *supra*, at pp. 70-72 (slip op.).) Clean Coalition/Sierra Club assert that these maps do not have data that will help developers determine potential transmission impacts, as determined by the IOUs. (Clean Coalition/Sierra Club Rehrg. App., p. 10.)

Clean Coalition/Sierra Club do not raise any legal error. Rather, Clean Coalition/Sierra Club raise an implementation issue that is not appropriate for consideration in a rehearing application. (Pub. Util. Code, § 1732; Cal. Code Regs., tit. 20, § 16.1, subd. (c).) Thus, there is no basis for rehearing of this issue.

The interconnection maps are merely a tool for generators to use to identify potential project sites. The Decision stated that generators can use these maps to locate sites that have a *low likelihood* of transmission impacts; the use of these maps does not necessarily guarantee eligibility or approval of the project for the section 399.20 FiT Program. (See D.12-05-035, pp. 58 & 69-70 [projects must still meet project viability criteria].)

5. Allegations that the Decision's methodology for allocating capacity is unclear

Clean Coalition/Sierra Club claim that the Decision's methodology for allocating capacity is unclear and potentially contradictory. (Clean Coalition/Sierra Club Rehrg. App., pp. 10-11.) According to Clean Coalition/Sierra Club, it's not clear that each two-month adjustment period has a capacity sum of the two months. They also state that the Decision does not specify how to handle contracted capacity from the AB 1969 FiT contracts.

The fact that Clean Coalition/Sierra Club are unclear about aspects of the Decision does not constitute legal error or a basis for rehearing of the Decision. (Pub. Util. Code, § 1732; Cal. Code Regs., tit. 20, § 16.1, subd. (c).) But we recognize that aspects of the Decision's discussion of the incremental release of capacity may have caused confusion and take this opportunity to make some clarifications.

The Decision stated that the utilities are to incrementally release a portion of their total program capacity allocation every two months for a 24-month period. (D.12-05-035, p. 119 [COL 28].) The Decision instructed: "To implement this directive, each utility must divide the total program capacity by 24 and then assign one third into each product type." (D.12-05-035, p. 49.) The Decision also provided that during the first allocation period, i.e. months 1 and 2, there is a minimum allocation of 3 MW for each product type. (D.12-05-035, p. 49.) This 3 MW is to be deducted from each utility's total capacity allocation prior to the allocation among product types.

It appears that there is some confusion in that there are 12 adjustment periods but the Decision directed the utilities to divide the total program capacity by 24. This directive may also be confusing in light of the mandatory 3 MW allocation during the first period. We modify the Decision, as set forth in the ordering paragraphs below, to clarify that: (1) the utilities should divide the total program capacity by 12 and then assign one-third into each product type; and (2) if dividing the total program capacity by 12 results in less than 3 MW being allocated to a product type per adjustment period, the utilities are to first allocate the minimum 3 MW per product type in the first adjustment period, and then equally allocate their remaining capacity among the three product types over the remaining 11 adjustment periods. We also clarify that the terms "initial starting capacity" and "initial capacity allocation" both refer to the amount of capacity allocated to each adjustment period. (See D.12-05-035, pp. 46-47, 48.)

With regard to the capacity under contract under the AB 1969 program, the Decision found that this capacity must be subtracted from each utility's total capacity allocation. (D.12-15-035, p. 77.) To the extent that there is any confusion, we clarify that

each utility is to subtract this capacity from its total capacity allocation prior to allocation among the three product types.

Clean Coalition/Sierra Club also allege that the allocation methodology may result in less than 3 MW being available for a project, which contradicts SB 32's allowance of up to 3 MW per project. (Clean Coalition/Sierra Club Rehrg. App., pp. 10, 11-13.) This allegation lacks merit. The statute states that in order for a generator to be eligible for the section 399.20 FiT, it must have an effective capacity of not more than 3 MW. (Pub. Util. Code, § 399.20, subd. (b)(1).) The statute does not require an allowance of 3 MW per project; it merely places size limitations on the generators that can participate in the FiT program. The fact that a generator may be eligible for the FiT does not guarantee participation in the program. There is a limited amount of capacity available under the program. Further, in implementing the FiT and the RPS program, we are also required to consider other factors such as the impact on ratepayers and cost. (Pub. Util. Code, §§ 399.15, subds. (c) and (d), 399.20, subd. (d)(4), 451.) The Decision adopted the incremental release of capacity "to minimize ratepayer exposure to a large number of non-competitively priced contracts while ensuring that some capacity is available for each product type, for which there is market interest." (D.12-05-035, pp. 49-50.)

Furthermore, the Decision did provide for changes to be made to the adjustment mechanism and allocation methodology depending on the market's response. Because the adjustment mechanism is a new feature of the FiT program, the Decision ordered utilities to convene stakeholder meetings within the first year of the program to solicit market experience with the price adjustment mechanism and authorized the utilities to file an advice letter to seek changes to the mechanism. (D.12-05-035, pp. 50 & 124 [Ordering Paragraph ("OP") 3].) The AB 1969 program is still in effect and, therefore, it is not presently known exactly how much capacity will be allocated to each adjustment period under the 3 MW FiT Program.

6. Allegation that the Decision is unclear regarding the status of the AB 1969 program

Clean Coalition/Sierra Club allege that the failure of the Decision to clarify whether the AB 1969 Program is suspended or not has created uncertainty. (Clean Coalition/Sierra Club Rehrg. App., pp. 13-14.) This allegation is moot. Subsequent to the issuance of the Decision, the Administrative Law Judge ("ALJ") issued a ruling clarifying that the existing FiT Programs implemented under AB 1969 will remain effective until replaced by the new tariffs ordered in the Decision. (*Administrative Law Judge's Ruling Clarifying Status of Existing Assembly Bill 1969 Feed-In-Tariff Program Per the Motion by Southern California Edison Company*, dated July 10, 2012.)

E. Allegations in CARE's Rehearing Application

1. Allegation that the Decision is stayed

CARE claims that because it filed its rehearing application within 10 days of issuance of the Decision, the Decision is stayed for at least 60 days. (CARE Rehrg. App., p. 1.) This claim lacks merit.

CARE does not cite to any legal authority or provide any explanation as to why its filing of a rehearing application would stay the Decision. The filing of a rehearing application ordinarily does not result in an automatic stay of a decision. (Pub. Util. Code, § 1735.) CARE may be relying on section 1733(a), which provides:

> Any application for a rehearing made 10 days or more before the effective date of the order as to which a rehearing is sought, shall be either granted or denied before the effective date, or the order shall stand suspended until the application is granted or denied; but, absent further order of the commission the order shall not stand so suspended for more than 60 days after the date of filing of the application, at which time the suspension shall lapse, the order shall become effective, and the application may be taken by the party making it to be denied.

But CARE did not file its rehearing application 10 days or more before the effective date of the Decision. The Decision was effective on May 24, 2012. CARE filed its rehearing

application on June 8, 2012. Therefore, there is no basis for a stay pursuant to section 1733(a) or any other law.

2. Allegation that the Decision misstates PURPA's requirements

CARE alleges that the Decision inaccurately cites to PURPA because it did not include citations to the Code of Federal Regulations and list all the codified sections of PURPA found in title 16 of the United States Code. (CARE Rehrg. App., p. 8 citing D.12-05-035, p. 19, fn. 17.) CARE fails to demonstrate any error. Footnote 17 states that "PURPA is codified in scattered sections of 16 U.S.C., including [§§ 796, 824a-3 and 2601 et seq]." Footnote 17 provided examples of some of the codified sections of PURPA but did not state that it is providing an exhaustive list of all of the sections of PURPA contained in title 16 of the United States Code. Further, the Code of Federal Regulations contains regulations implementing PURPA, not the codified sections of PURPA.

3. Allegation that the Decision misstates the definition of Qualifying Facilities ("QFs")

The Decision states that, "In general, QFs are alternative energy power production facilities that are primarily renewable or gas-fired cogeneration units." (D.12-05-035, p. 11.) As support for this statement, the Decision cited "*See* 18 C.F.R. § 292.304(a)." (D.12-05-035, p. 11, fn. 19.) CARE claims that this definition is inaccurate and unsupported by the citation provided in footnote 19 of the Decision. (CARE Rehrg. App., pp. 9-10.) CARE fails to demonstrate that the statement in the Decision is inaccurate. (See also 18 C.F.R. §§ 292.101, subd. (b)(1) & 292.203 [providing definition and general requirements for qualification of QFs].) The statement does not purport to provide an exhaustive list of all facilities that can be QFs. Moreover, although 18 C.F.R. § 292.304(a) deals with rates for purchases, it also references the qualifying facilities from which these purchases are made.

4. Allegation that the Decision does not cite to the most recent guidance regarding avoided costs provided by the FERC

The Decision stated that the adopted Re-MAT price is consistent with PURPA, including the most recent guidance provided by the FERC regarding avoided cost pricing for QFs, the *FERC Clarification Order*. (D.12-05-035, p. 11.) CARE asserts that this statement is untrue because the most recent guidance from the FERC would have been *California Public Utilities Commission* ("*FERC Order Denying Rehearing*") (2011) 134 FERC ¶ 61,044. (CARE Rehrg. App., p. 10.) The *FERC Order Denying Rehearing* denied rehearing of the *FERC Clarification Order*. CARE does not explain what additional guidance regarding avoided cost pricing for QFs the *FERC Order Denying Rehearing* provided. CARE's rehearing application cites to paragraphs 6 and 7 of the *FERC Order Denying Rehearing*. But these paragraphs merely recap the proceedings leading up to the *FERC Clarification Order* and the findings of that order. CARE also cites to paragraph 32, but in that paragraph, the FERC defended the finding in the *FERC Clarification Order* that a multi-tiered avoided cost rate structure is not prohibited by PURPA or FERC's regulations. Thus, CARE does not demonstrate that we erred in characterizing the *FERC Clarification Order* as the most recent guidance from FERC on avoided cost pricing for QFs.

5. Allegation that the pricing and interconnection violates PURPA

CARE alleges that "the pricing and interconnection violates PURPA." (CARE Rehrg. App., p. 9 citing 18 C.F.R. §§ 292.303, subds. (a)(1), (a)(2), (c)(1), (d) & 292.304, subds. (a)-(e).) CARE fails to demonstrate that the Decision violates PURPA.

CARE makes the conclusory allegations that the Decision violates various subdivisions of 18 C.F.R. § 292.303 without providing any explanation. (See CARE Rehrg. App., p. 9.) CARE fails to demonstrate any legal error or that rehearing is warranted based on any violation of 18 C.F.R. § 292.303. (See Pub. Util. Code, § 1732; Cal. Code Regs., tit. 20, § 16.1, subd. (c).) Merely identifying a law, without providing any explanation of how it applies to the instant case, is insufficient to meet the

requirements of section 1732, which requires that a rehearing application "set forth specifically the ground or grounds on which the applicant considers the decision or order to be unlawful." (Pub. Util. Code, § 1732; see also *Order Modifying Decision (D.) 07-10-013 and Denying Rehearing of the Decision as Modified* [D.10-07-050] (2010) __ Cal.P.U.C.3d __, at p. 19 (slip op.).) The purpose of a rehearing application is to "alert the Commission to a legal error, so that the Commission may correct it expeditiously." (Cal. Code Regs., tit. 20, § 16.1, subd. (c).) A conclusory allegation, which does not provide any explanation but leaves the Commission to guess how its decision may be in error, does not serve this purpose.

18 C.F.R. § 292.303 imposes certain obligations on electric utilities. 18 C.F.R. § 292.303(a) and (d) describe an electric utility's obligation to purchase from a QF. 18 C.F.R. § 292.303(c)(1) requires an electric utility to make the necessary interconnections with a QF to accomplish a purchase or sale. CARE does not cite to any aspect of the Decision that violates these subdivisions. CARE only cites to page 10, section 3.1 of the Decision. (CARE Rehrg. App., p. 9.) But this section merely summarizes federal law with regard to setting avoided cost.

18 C.F.R. § 292.304 contains provisions for determining the rates for purchases from QFs. Although CARE's rehearing application claims violations of subdivisions (a) through (e) of 18 C.F.R. § 292.304, CARE does not specify how the pricing adopted in the Decision violates each of these subdivisions. (See CARE Rehrg. App., p. 9.) We address herein only the allegations regarding pricing that are actually specified in CARE's rehearing application. With regard to the allegations of error that are conclusory and without explanation, we deny rehearing as these allegations also fail to meet the requirements of section 1732 and Rule 16.1 of the Commission's Rules of Practice and Procedure.

CARE alleges that the Decision errs because PURPA and the FERC require the setting of administratively determined calculations using the data provided by the utilities. (CARE Rehrg. App., p. 11 citing 18 C.F.R. § 292.302, subd. (b)(1).) There is no such requirement in PURPA. PURPA requires that the rate for purchases from QFs be

just and reasonable, non-discriminatory, and not exceed the utilities' avoided cost. (See 18 C.F.R. § 292.304, subd. (a).) The FERC gives wide latitude to states to implement PURPA and to determine what constitutes avoided cost. (*Independent Energy Producers Ass'n v. Pub. Util. Com.* (9th Cir. 1994) 36 F.3d 848, 856; *American REF-FUEL Company of Hempstead* (1989) 47 FERC ¶ 61,161, at ¶ 61,533.) The FERC has found that a rate based on a competitive solicitation may comply with avoided cost requirements. (See, e.g. *North Little Rock Cogeneration, L.P. v. Entergy Services, Inc.* (1995) 72 FERC ¶ 61,263, at ¶ 62,173.) In this instance, we found that a starting price based on a comparable renewable energy market, the RAM, coupled with a price adjustment mechanism, complied with avoided cost requirements. (D.12-05-035, pp. 38-40.)

CARE argues that the RAM Program is not the closest comparison to the Re-MAT. CARE asserts that we should have used the 2010 and 2011 Solar Photovoltaic Program ("SPVP") results rather than the RAM results. (CARE Rehrg. App., pp. 10, 11-13.) CARE does not explain how the SPVP results are more comparable when the FiT Program is not limited to only solar resources. The section 399.20 FiT Program seeks to procure energy from renewable generation of 3 MW or less, and to take into account the value of different electricity products, including baseload, peaking, and as-available electricity. (Pub. Util. Code, § 399.20, subds. (b) & (d)(2)(C).)

CARE alleges that a price based on the RAM is a "false avoided cost" since it is lower than the MPR and the Decision states that even an MPR-based rate is not appropriate. (CARE Rehrg. App., p. 13.) This allegation lacks merit. CARE fails to explain why the RAM is a "false avoided cost." The Decision explained why it was reasonable to base the Re-MAT price on the RAM, which is based on a renewable market, rather than on the MPR, which is based on the cost of a natural gas-fired plant.

(D.12-05-035, p. 31.)[9] The Decision found that the MPR price may be too high or too low for different FiT product types. (D.12-05-035, p. 31.) Moreover, the RAM is only the starting point for the Re-MAT price because it includes a price adjustment mechanism that will respond to market conditions for each product type and account for differences between the RAM and Re-MAT projects.

CARE claims that PURPA does not allow for the price adjustment mechanism described in the Decision, "which is a price adjustment mechanism that *has not been* made by the State Regulating Authority, the [Commission]...." (CARE Rehrg. App., p. 14, emphasis in original.) CARE does not cite to any authority for the proposition that PURPA prohibits a price adjustment mechanism. As explained above, the states have wide latitude to determine avoided cost. CARE is also incorrect that the price adjustment mechanism has not been made by the state regulating authority as the Commission, which is the state regulating authority, adopted the price adjustment mechanism in the Decision. (D.12-05-035, p. 119 [COLs 25 & 26].)

6. Allegations that the Decision violates the FERC's mandates regarding technology and size-specific pricing

CARE claims that the FERC has ordered technology and size-specific pricing. (CARE Rehrg. App., p. 11.) According to CARE, using the same price for all 3 IOUs and for all 3 product types violates PURPA and the FERC's rules and orders

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[9] The Decision suggested that the MPR is based on a "market." (See D.12-05-035, p. 31.) The MPR is an administratively determined rate and not based on a "market." We modify the Decision, as set forth in the ordering paragraphs below, to delete any suggestion that the MPR is based on a "market." We also note that we have adopted pricing based on the MPR to determine the avoided cost for other programs implemented pursuant to PURPA, such as the Assembly Bill 1613 (Stats. 2007, ch. 713) ("AB 1613") combined heat and power ("CHP") program. (See, e.g., *Decision Adopting Policies and Procedures for Purchase of Excess Electricity Under Assembly Bill 1613* [D.09-12-042] (2009) __ Cal.P.U.C.3d __, pp. 74 [FOF 22] & 78 [COL 9] (slip op.).) We determined that a market-based price was appropriate for establishing the Re-MAT price because we found that the renewable market was now sufficiently robust to serve as a point of reference. (D.12-05-035, p. 117 [COL 11].) But the finding in the Decision that the Re-MAT price should not be based on the MPR does not modify our previous findings that an MPR-based rate is the appropriate avoided cost rate for other programs implemented pursuant to PURPA.

because avoided cost is to be differentiated by technology. (CARE Rehrg. App., pp. 14-15 citing 18 C.F.R. § 292.304, subd. (c)(3)(ii), *FERC Clarification Order*, *supra*, and *FERC Order Denying Rehearing*, *supra*.) These allegations lack merit.

CARE misreads the pricing adopted in the Decision. The RAM price is merely the starting point for the Re-MAT price. Each utility is to apply a price adjustment mechanism to the starting price for each product type based on market interest. (D.12-05-035, p. 119 [COLs 25 & 26].) Each utility is also to adjust the starting price by time-of-delivery factors. (D.12-05-035, p. 119 [COL 24].) The starting price, in conjunction with the price adjustment mechanism and adjustment by time-of-delivery factors, may result in different prices for the different product types for each utility.

CARE is also mistaken that the FERC has ordered technology and size-specific pricing. 18 C.F.R. § 292.304(c)(3)(ii) provides that standard rates for purchases from QFs "[m]ay differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies." The *FERC Clarification Order* found that: "the concept of a multi-tiered avoided cost rate structure can be consistent with the avoided cost rate requirements set forth in PURPA and [the FERC's] regulations." (*FERC Clarification Order*, *supra*, 133 FERC ¶ 61,059, at P 26.) The FERC clarified that in determining the avoided cost rate, the Commission "may take into account actual procurement requirements, and resulting costs, imposed on utilities in California."[10] (*Ibid.*) Therefore, although federal law permits states to set different avoided costs for various technologies, states are not necessarily required to do so.[11]

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10 We modify the Decision, as set forth in the ordering paragraphs below, to clarify that the *FERC Clarification Order* permits the Commission to adopt avoided costs differentiated for particular sources of energy that a utility must purchase. (See *FERC Clarification Order*, *supra*, 133 FERC ¶ 61,059, at P 26; see also *Id*. at P 17, fn. 33.)

11 The states have authority over the procurement decisions of the retail utilities, including the resource portfolios of the retail utilities. (See *New York* v. *FERC* (2002) 535 U.S. 1, 24 *quoting Order No. 888* (1996) FERC Stats. & Regs., Regs. Preambles, Jan. 1991-June 1996, ¶ 31,036, ¶ 31,792, n. 544.)

7. Allegation that the Commission cannot guard ratepayers and small generators from market manipulation or malfunction

The Decision stated that to guard against ratepayer exposure to excessive costs due to market manipulation or market malfunction of the Re-MAT pricing mechanism, the utilities shall file a motion to temporarily suspend all or part of the FiT program when evidence of market manipulation exists. (D.12-05-035, p. 47.)

CARE alleges that the Decision errs in that only a federal court can guard ratepayers and small generators. (CARE Rehrg. App., pp. 15-16.) CARE asserts that the FERC has indicated that the Commission is not in compliance with PURPA. (CARE Rehrg. App., p. 15 citing *Southern California Edison Company, et al*. (2011) 134 FERC ¶ 61,271.) CARE also states that a lawsuit pending in federal district court, *Solutions for Utilities, Inc., et al. v. California Public Utilities Commission, et al.* (C.D. Cal., No. CV 11-04975 SJO (JCGx)), alleges that the Commission, utilities, and the FERC "cannot be left to act upon market manipulation and market malfunction." (CARE Rehrg. App., p. 15.)

CARE's allegations lack merit. The Commission has the authority and responsibility to ensure just and reasonable rates and charges for ratepayers. (See, e.g., Cal. Const., art. XII, §§ 1-6; Pub. Util. Code, §§ 451 & 701.) The Commission is charged with implementing the section 399.20 FiT Program, including adopting a pricing mechanism and ensuring that ratepayers remain indifferent to the rates and charges of the FiT. (Pub. Util. Code, § 399.20, subd. (d).) Thus, it is within the Commission's authority to temporarily suspend the program it is charged with implementing where ratepayers are exposed to excessive costs due to market manipulation or malfunction. Further, in setting avoided cost rates, the Commission has the obligation to ensure that rates for utility purchases are just and reasonable and in the public interest. (18 C.F.R. § 292.304, subd. (a)(i).)

CARE offers no legal authority for the proposition that only a federal court can protect ratepayers from market manipulation or malfunction affecting a PURPA

program. *Southern California Edison Company, et al.* is not on point. That proceeding did not involve alleged market manipulation or malfunction, but was a petition under Section 210(h) of PURPA, 16 U.S.C. § 824a-3(h), alleging that the rate for the Commission's AB 1613 CHP program was in excess of the utilities' avoided cost. (*Southern California Edison Company, et al., supra,* 134 FERC ¶ 61,271, at P 1.) The FERC declined to initiate an enforcement action against the Commission and stated that the utilities may bring an enforcement action alleging violations of PURPA in the "appropriate court." (*Id.* at P 2.) Contrary to CARE's allegations, the FERC did not find that the Commission had violated PURPA. Even if the FERC had made such a finding, which it did not, this still would not mean that the Commission lacks the authority to protect ratepayers.

With regard to the lawsuit in federal district court, CARE fails to explain how allegations raised by a party in a lawsuit constitute legal authority. Moreover, the federal district court recently granted the defendants' Motion for Summary Judgment and dismissed the plaintiff's claims in that case. Although the court dismissed the plaintiff's claims for lack of standing, the court also noted that: "Plaintiff would have likely failed on its substantive PURPA arguments regardless." (Order Granting Motion for Summary Judgment, *Solutions for Utilities, Inc., et al. v. California Public Utilities Commission, et al.* (C.D. Cal., Jan. 3, 2013, No. CV 11-04975 SJO (JCGx)) at p. 9 (slip op.).)

Finally, *Morgan Stanley Capital Group Inc. v. Public Utility District No. 1 of Snohomish County* (2008) 554 U.S. 527, which is cited by CARE, also is inapposite. *Morgan Stanley* did not hold that only a federal court has jurisdiction to address market manipulation or malfunction, and instead addressed the standards for the FERC's review and modification of wholesale electricity contracts under Section 205 of the Federal Power Act, 16 U.S.C. § 824d.

8. Allegation that the price adjustment mechanism violates laws prohibiting market manipulation

CARE asserts that the Decision violates 18 C.F.R. §§ 1c.1 and 1c.2, which prohibit market manipulation of the natural gas and electric energy markets. (CARE

Rehrg. App., pp. 16-19.) According to CARE, it is inevitable that there will be 100% program subscription for two years, and, therefore, the price adjustment mechanism would decrease the Re-MAT price to the point that it would become a negative value, which would mean that a generator would eventually have to pay the utilities to take its electric energy. (CARE Rehrg. App., pp. 17-18.)

CARE fails to demonstrate that the price adjustment mechanism will somehow result in or contribute to market manipulation. CARE mistakes how the price adjustment mechanism functions. The Decision provided that the Re-MAT price will decrease if there are five projects with different developers in the queue for a particular product type and if the subscription in the previous two-month period equaled 100% or more of the initial capacity allocation for that product type. (D.12-05-035, p. 48.) CARE appears to erroneously equate a developer being in the queue with a developer subscribing to the program. Once in the queue, a generator may still accept or reject the price. (D.12-05-035, p. 45.) CARE's allegations are based on the flawed premise that a generator would accept a price that would not account for its costs. The entire point of the adjustment mechanism is that it allows the Re-MAT price to adjust to the market price.

We modify the Decision, however, to clarify that subscription in a two-month period cannot equal more than 100% of the initial capacity allocation for a product type. In describing the price adjustment mechanism, the Decision suggested that subscription can be greater than 100%. (D.12-05-035, p. 48.) But this is not possible because any unsubscribed capacity at the end of a two-month period is reallocated to the end of the 24 months, starting with a new period at months 25-26. (D.12-05-035, p. 49.)

9. Allegations regarding approval of RAM contracts

CARE's rehearing application alleges that the Energy Division's approval of the utilities' advice letters based on the first RAM solicitation violated GO 96-B. CARE alleges that pursuant to GO 96-B, these advice letters should have been treated as Tier 3 advice letters, which require Commission approval, rather than as Tier 2 advice

letters, which only require approval by the Energy Division. (CARE Rehrg. App., pp. 19-22; see also General Order 96-B, Energy Industry Rule 5.)

CARE's allegations do not involve any claims of legal error in the Decision itself. We did not approve the RAM contracts in the Decision. Thus, the allegations regarding the approval of the RAM contracts do not provide a basis for rehearing of the Decision. (Pub. Util. Code, § 1732; Cal. Code Regs., tit. 20, § 16.1, subd. (c).) CARE's rehearing application also omits the fact that in Resolution E-4414, which further implemented the RAM, we adopted a standard power purchase agreement for each utility and directed the utilities to submit executed RAM contracts through a Tier 2 advice letter. (Resolution E-4414, dated August 18, 2011, p. 45 [OP 4].)

10. Allegation regarding daisy-chaining of contracts

The Decision adopted measures to prevent daisy-chaining of projects to evade the project size restrictions of the § 399.20 FiT Program. (D.12-05-035, pp. 120 [COL 34] & 125[OP 6].) Providing examples of certain RAM contracts, CARE claims that the Commission has a history of approving contracts in excess of the 20 MW RAM size restriction. (CARE Rehrg. App., pp. 23-24.)

CARE fails to specify any legal error in the Decision. CARE's rehearing application does not allege that the Commission violated any law by adopting measures to prevent daisy-chaining with regard to the § 399.20 FiT Program. To the extent CARE is arguing that the Commission erred in approving the RAM contracts, there is no basis for rehearing of the Decision as the Commission did not approve these contracts in the Decision. (Pub. Util. Code, § 1732; Cal. Code Regs., tit. 20, § 16.1, subd. (c).)

F. The District's Rehearing Application

The District requests that we grant rehearing on the issue of whether or not existing contracts should be included in the new 750 MW cap implemented by the Decision. The District's rehearing application solely relies on a motion it filed on June 27, 2012, requesting that we reopen the record in order to take official notice of the existing less than 3 MW contracts that are for facilities in the IOUs' service territories.

The District's rehearing application is rejected for failing to comply with the requirements of section 1732 and Rule 16.1 of the Commission's Rules of Practice and Procedure, which both require that a rehearing application "set forth specifically" the grounds on which the decision is unlawful. Reference to a separate motion does not "set forth specifically" the claims of error in a rehearing application. (Pub. Util. Code, § 1732; see also *Order Modifying Decision (D.) 11-12-053 and Denying Rehearing of the Decision as Modified* [D.12-08-046] (2012) __ Cal.P.U.C.3d __ at pp. 36-37 (slip op.) [rejecting claims not stated in the rehearing application itself].)

III. CONCLUSION

For the reasons stated above, D.12-05-035 is modified to: (1) explain that the adopted pricing mechanism should account for all of the generator's costs, including environmental compliance costs; (2) delete the statement that the Commission seeks to pay generators the price needed to build and operate a renewable generation facility; (3) delete statements that imply that avoided costs under PURPA are based in part on avoided ratepayer costs; (4) correct statements regarding section 399.20(f)'s requirement that the tariff be available on a "first-come-first-served basis;" (5) clarify the reasons for declining to adopt a location or transmission adder; (6) delete the statement that the FiT program may be quickly subscribed; (7) clarify how the program's capacity is allocated and incrementally released; (8) delete statements that the MPR is based on a "market;" (9) clarify statements regarding the legal requirements for setting avoided cost and the holdings of the *FERC Clarification Order*; and (10) correct the statement that subscription in a two-month period can equal more than 100% of the initial capacity allocation for a product type. D.12-05-035 is also modified to correct various typographical errors. Rehearing of D.12-05-035, as modified, is denied.

THEREFORE, IT IS ORDERED that:

1. D.12-05-035 shall be modified as follows:

   a. The third sentence of the second paragraph on page 2 is modified to replace "principle" with "principal."

b. The last sentence on page 4 is modified to replace "an electric corporations'" with "an electric corporation's."

c. The last complete sentence on page 9 is modified to replace the title of the ALJ's Ruling to "*ALJ's Ruling Regarding Setting Schedule for Briefs on Implementation of Senate Bill 32*."

d. The first two sentences of section 3 on page 10 are modified to read:

> "In implementing the amendments to the § 399.20 FiT Program, we rely on federal law, specifically, avoided cost requirements under the Public Utility Regulatory Policies Act of 1978 (PURPA).[17] We also rely upon § 399.20 and state laws governing statutory construction."

e. The first sentence of section 3.1 on page 10 is modified to insert "the" before "Federal Power Act."

f. The last sentence of the second paragraph on page 11 is modified to replace "avoided costs pricing" with "avoided cost pricing."

g. The paragraph beginning with "Based on the *FERC Clarification Order*…" on page 12, which continues on page 13, is deleted and replaced with the following:

> "Based on the *FERC Clarification Order*, we determined in D.11-04-033 that we have a wide degree of latitude in setting the avoided cost. We apply the same logic for the § 399.20 FiT Program. Specifically, based on the FERC's clarification, the Commission may adopt avoided costs differentiated for particular sources of energy that a utility must purchase. In addition, the Commission may adopt a multi-tiered avoided cost rate structure. These clarifications expand the pricing options the Commission can consider when determining the § 399.20 FiT Program price."

h. The last sentence on page 15, which continues on page 16, beginning with "Since the cross-reference to § 399.15…" is modified to read:

> "Since the cross-reference to § 399.15 has been removed pursuant to SB 2 1X, electricity purchased under § 399.20 is no longer required to be tied to the MPR as it was calculated for purposes of the larger RPS Program."

i. Footnote 44 on page 29 is deleted in its entirety.

j. The fifth sentence in the second paragraph on page 31, which states, "Instead, it reflects the costs of a different energy market, fossil fuels" is deleted.

k. The last sentence in the second paragraph on page 31, which begins, "Now the renewable market is sufficiently robust…" is modified to read:

> "Now the renewable market is sufficiently robust to serve as the point of reference for establishing the market price for small renewable projects rather than the very different benchmark used for the MPR, which is based on the costs of a combined-cycle natural-gas power plant."

l. The last sentence in the second paragraph on page 32, which begins, "In addition, the methodologies…" is modified to read:

> "In addition, the methodologies used for these adders were generally based on avoided societal costs, and not avoided utility costs, and are therefore not the type of avoided costs permitted under PURPA."

m. The second, third, and fourth sentences in the first full paragraph on page 33, beginning with "As stated above, many of the proposed adders…" are modified to read:

> "As stated above, many of the proposed adders are overly broad societal costs and not based on the avoided costs to utilities. In addition, these adders could increase the contract price above the market price of generation from eligible renewable energy resources and lead to overpayment. As discussed below, the FiT price calibrates to market prices and to market demand, which leads both to reasonable

ratepayer costs and prices that can work to stimulate market demand."

n. The last sentence on page 33, which continues on page 34, beginning with "In doing so, we must balance…" is modified to read:

"In doing so, we must balance a number of competing interests, and find that, at this time, unique prices for separate technologies are not required by state law or in the best interest to ratepayers."

o. The first full paragraph on page 34 beginning with "Regarding the state law issue…" is modified to read:

"Regarding the state law issue, the parties do not address the fact that § 399.20 does not specifically direct the Commission to account for the unique cost of each technology. The plain language of § 399.20 does not require that technology-specific costs be included in a FiT Program price methodology."

p. The second sentence in the third full paragraph on page 34 beginning with" While federal law, as discussed above…" is modified to read:

"While federal law, as discussed above, provides the Commission with the latitude to take into account state energy procurement requirements when establishing avoided costs, the state statute, as codified in § 399.20, does not require the Commission to consider technology-specific costs when determining the § 399.20 FiT Program price."

q. The first sentence in the first full paragraph on page 35 is modified to delete the word "an" before "administratively-determined calculations."

r. The first sentence in the fourth full paragraph on page 35, which starts, "Accordingly, we do not adopt technology-specific pricing…" is modified to read:

"Accordingly, we do not adopt technology-specific pricing as it is not required by § 399.20 and

does not advance our policy guidelines for implementing the § 399.20 FiT Program."

s. The first three sentences of the second paragraph of section 5.6 on pages 37-38, beginning with "We do not adopt other components…" are modified to read:

"We do not adopt other components of the Renewable FiT Staff Proposal, including the location adder or a transmission adder because we find these components, as proposed during the proceeding, to be inconsistent with existing law. Any location or transmission adder must be based on costs that are found to be actually avoided by the utilities. (18 C.F.R. § 292.304, subd. (a)(2); *FERC Clarification Order, supra,* 133 FERC ¶ 61,059, at P 31.) In this case, we agree with the concerns expressed by SCE and the other utilities, and find that the record does not support a finding that the location and transmission adders proposed during the proceeding represent actual costs that would be avoided by the utilities. (See, e.g., *Southern California Edison Company's Reply Comments on the October 13, 2011 Renewable FIT Staff Proposal*, dated November 14, 2011, pp. 12-13; *Pacific Gas and Electric Company's Comments on Staff Proposal Regarding the Implementation of Section 399.20*, dated November 2, 2011, pp. 17-19.)

t. The third paragraph on page 39 beginning with "Our finding is based…" is modified to read:

"Our finding is based on the fact that the renewable market has evolved, and is now sufficiently robust to serve as the point of reference for the market price for small renewable projects. The discussion above at Section 5 fully addresses this matter."

u. The second full sentence on page 40, beginning with "Nevertheless, while not identical…" is deleted and replaced with the following:

"We address the disparity between the RAM and the § 399.20 FiT Program markets by adopting a price adjustment mechanism, described further in Section

6.4, which will enable the FiT price to be responsive to market conditions. We find that the adopted Re-MAT, which uses the RAM as a starting price and employs a price adjustment mechanism, establishes a market-based avoided cost for the § 399.20 FiT Program."

v. The first and second sentences in the second paragraph on page 41 are both modified to insert "the" before "long-term market price."

w. The second paragraph on page 42, which discusses environmental compliance costs, is modified to read:

"Section 399.20(d)(1) provides that the tariff shall provide for payment of, among other things, all current and anticipated environmental compliance costs, including, but not limited to, mitigation of emissions of greenhouse gases and air pollution offsets associated with the operation of new generating facilities in the local air pollution control or air quality management district where the electric generation facility is located. Re-MAT theoretically includes, as embedded within the starting price, general costs associated with producing renewable energy. As the Re-MAT should calibrate to the market price of the renewable energy, we find that the Re-MAT price should account for all of a generator's costs, including the generator's environmental compliance costs."

x. The third sentence of section 6.3 on page 42, beginning with "Our decision reflects an effort…" is modified to read:

"Our decision reflects an effort to better capture the value provided by different product types, which should accurately reflect the value of the different technologies that produce these products."

y. The last sentence in the first full paragraph on page 43, beginning with "This is a reasonable starting price…" is modified to delete the word "distributed" before "generation."

z. Footnote 48 on page 43 is modified to replace "advice letter" with "advice letters."

aa. Footnote 50 on page 44 is modified to read:

> "*Southern California Edison Company's Program Implementation Proposal Pursuant to Section 399.20 Ruling Dated June 27, 2011*, dated August 5, 2011, Appendix A Schedule MP FiT, Sheet 5, Special Condition #8 MP FiT Pricing and Cumulative Procurement Targets."

bb. The first sentence in the second full paragraph on page 45, beginning with "The price adjustment will be triggered…" is modified to insert "at" before "least."

cc. The first sentence of the third full paragraph on page 47, beginning with "To guard against ratepayer exposure…" is modified to "all part of program" with "all or part of the program."

dd. The second sentence on page 48, beginning with "The condition for a price decrease…" is modified to read:

> "The condition for a price decrease is if subscription in a two-month period equals 100% of the initial capacity allocation for that product type."

ee. The illustrations of price decreases on page 48 are all modified to replace "100% or more" with "100%."

ff. The first sentence on page 49 is modified to replace "we direct utilities" with "we direct the utilities."

gg. The second and third paragraphs on page 49, beginning with "To implement this directive…" is modified to read:

> "To implement this directive, each utility must divide the total program capacity by 12 and then assign one-third into each product type.
>
> In the first adjustment period, i.e. Months 1-2, we require that each utility allocate a minimum of 3 MW to each product type. The same minimum obligation would apply to Months 25-26, if applicable. If dividing the total program capacity by 12 results in less than 3 MW being allocated to a product type per adjustment period, the utilities are to first allocate the

minimum 3 MW per product type in the first adjustment period, and then equally allocate their remaining capacity among the three product types over the remaining 11 adjustment periods."

hh. Footnote 53 on page 49 is deleted.

ii. The first sentence in the second full paragraph on page 52, beginning with "However, we expect the price adjustment mechanism…" is modified to replace "produce type" with "product type."

jj. The first sentence in the third full paragraph on page 52, beginning with "For this reason, at this point in time…" is modified to replace "§ 399.20(d)(3)" with "§ 399.20(d)(4)."

kk. The last two full paragraphs on page 53 and the first full paragraph on page 54, beginning with "Turning now to the specific legislative directive…," and associated footnotes 56 and 57, are deleted in their entirety and replaced with the following:

> "Turning now to the specific legislative directive in § 399.20(d)(1) and consideration of an adder to reflect the cost of environmental compliance, a few parties submitted evidence on this topic. We find that much of this data reflects general environmental costs and not, as specified by the statute, the cost of environmental compliance.
>
> With regard to environmental compliance costs, we find that an adder for these costs is unwarranted, as the Re-MAT price should adjust to account for these costs. The rationale for a market-based price is that all of the generator's costs are included in the price because a generator would not bid something lower than its costs. In a market-based process, the seller determines the price it wishes to seek based on its understanding of the underlying project costs, and changes in those costs. (*Decision Adopting the Renewable Auction Mechanism* [D.10-12-048] (2010) __ Cal.P.U.C.3d __, p. 17 (slip op.).) In adopting the RAM, we found that a rational bidder would include all of its costs in its bid. (*Id*. at p. 85 [Finding of Fact 36].)

> Given that all costs incurred by a generator are presumed included in a market-based price, we see no reason why environmental compliance costs should be treated differently from any other costs incurred by a generator. A generator should include all of its costs, including any environmental compliance costs, in its price for the Re-MAT. The Re-MAT price adjusts based on market conditions and, thus, should account for these costs. (See also, *Southern California Edison Company's Comments to Section 399.20 Ruling dated June 27, 2011*, dated July 21, 2011, p. 4 [market-based process would allow current and anticipated environmental costs to be included in the price]; *Clean Coalition Reply Comments on ALJ Ruling*, dated August 26, 2011, p. 31 [price adjustment mechanism could result in a price that includes environmental compliance costs].) Therefore, we find that the Re-MAT complies with the legislative directive in § 399.20(d)(1) regarding environmental compliance costs, and is also consistent with PURPA's requirements that rates for QFs be based on the utilities' avoided costs, rather than a generator's costs."

ll. The second sentence in the second paragraph on page 58, beginning with "We further point out…" is modified to replace "legislation intent" with "legislative intent."

mm. Footnote 66 on page 59 is modified to read: "§ 399.20(d)(4)."

nn. The third to last sentence on page 60, beginning with "Similarly, we find today that Re-MAT…" is modified to replace "§ 399.20(d)(3)" with "§ 399.20(d)(4)."

oo. The second paragraph on page 61, beginning with "Accordingly, we find…" is modified to replace "§ 399.20(d)(3)" with "§ 399.20(d)(4)."

pp. Section 6.11 on pages 61 and 62 is deleted in its entirety and replaced with the following:

"Section 399.20(f) states that '[a]n electrical corporation shall make the tariff available … on a first-come-first-served basis.'

Section 399.20(f) discusses the obligation of the utilities, and does not discuss the Commission's authority to impose pricing, procurement, or other program requirements for the FiT. The Commission has broad authority over public utilities, including authority over the utilities' resource portfolios and procurement planning, and in implementing the RPS Program. (See, e.g., Cal. Const., art. XII, § 6; Pub. Util. Code, §§ 399.11 et seq., 454.5, 701.) The Commission has the authority to act even in cases where there is no express statutory authorization so long as the additional power and jurisdiction the Commission exercises are cognate and germane to the regulation of public utilities, and do not contravene or disregard an express legislative directive. (Pub. Util. Code, § 701; *Consumer Lobby Against Monopolies v. Public Utilities Com.* (1979) 25 Cal.3d 891, 905-906; *Assembly v. Public Utilities Com.* (1995) 12 Cal. 4th 87, 103.) Therefore, the Commission is not restricted from adopting additional program requirements for the FiT, so long as the imposition of these requirements does not contravene other statutory requirements.

In order to comply with section 399.20(f), the utilities should make their respective tariffs, which incorporate any program requirements required by statute or by the Commission, available on a first-come-first-served basis. Among other things, the utilities' tariffs must incorporate the pricing mechanism adopted pursuant to section 399.20(d). The utilities' tariffs should also incorporate the requirement that an equal portion of their allotted capacity be assigned to the three product types, baseload, peaking, and as-available. We find that this program requirement is warranted based on the legislative directive in section 399.20(d)(2)(C) that the Commission take into consideration the value of different electricity products in establishing a pricing methodology for the FiT."

qq. The third sentence in the third full paragraph on page 64, beginning with" We do, however, find…" is modified to replace "encouraging load to locate near load centers" with "encouraging generation to locate near load centers."

rr. The second sentence of section 9 on page 67, beginning with "Under D.07-07-27…" is modified to insert "the" before "Commission's § 399.20 FiT Program."

ss. The first two full sentences on page 76, beginning with "We are sensitive, however…" are deleted in their entirety.

tt. The following sentence is inserted before the last sentence in the first paragraph on page 77:

"Each utility is to subtract this capacity from its total capacity allocation prior to allocation among the three product types."

uu. The third sentence of the third paragraph of section 12.2 on page 77, beginning with "SCE suggests…" is modified to replace "each utilities'" with "each utility's."

vv. The fourth sentence in the second paragraph on page 80, beginning with "AECA's recommendation" is modified to replace "biogas project" with biogas projects."

ww. The first paragraph on page 81, beginning with "Today we decline to adopt a set aside…" is deleted in its entirety and replaced with the following:

"Today we decline to adopt a set aside for any specific technology. As created by the Legislature, the § 399.20 Program is intended to encourage electrical generation from eligible renewable energy resources but there is no statutory provision that directs us to consider a set-aside for any particular technology. To the extent that there is no statutory requirement requiring technological set-asides for the § 399.20 Program, it is within our authority and discretion to determine how to implement the program. We decline to adopt technological set-asides at this time because it is not required by statute, and because, as with

> technology-specific pricing discussed in Section 5.3, above, we find that technological-set asides are not consistent with our policy guidelines for the FiT Program."

xx. The third sentence of the second paragraph on page 81, starting with "In addition, it dedicates…" is modified to read:

> "In addition, consistent with § 399.20(d)(2)(C), it dedicates a certain portion of the capacity allocation to each product type."

yy. The first sentence of the first full paragraph on page 90, beginning with "Regarding the type of information…" is modified to insert "the" before "§ 399.20 FiT Program."

zz. The second sentence in the first paragraph of Section 25 on page 105, beginning with "Solutions for Utilities seeks…" is modified to insert "the" before "§ 399.20 FiT Program."

aaa. The second sentence of footnote 96 on page 105 is modified to replace "R.06-03-027" with "R.06-05-027."

bbb. The first sentence of the third paragraph on page 106 is modified to replace "Clean Coalition's petition for modification" with "Solutions for Utilities' petition for modification."

ccc. FOF 3 on page 109 is modified to read:

> "The MPR is a price based on the costs of a natural gas-fired electric plant, and not a renewable generator. The MPR reflects the costs of fossil fuels."

ddd. FOF 5 on page 109 is modified to read:

> "The renewable market is sufficiently robust to serve as the point of reference for establishing the market price for small renewable projects rather than the MPR, which reflects the costs of a combined-cycle natural-gas power plant."

eee. FOF 6 on page 109 is modified to replace "ratepayer costs" with "utility costs."

fff. FOF 15 on page 110 is modified to read:

> "The Re-MAT price should increase or decrease based on market interest in a product type, which may be determined by how many projects execute contracts at a particular Re-MAT price."

ggg. FOF 20 on page 111 is modified to replace "§ 399.20(d)(3)" with § 399.20(d)(4)."

hhh. FOF 21 on page 111 is deleted in its entirety and replaced with the following:

> "There is no statutory provision requiring the adoption of pricing on a technology-specific basis."

iii. FOF 22 on page 111 is deleted in its entirety and replaced with the following:

> "A market-based price accounts for all of a generator's costs, including environmental compliance costs."

jjj. FOF 23 on page 111 is deleted in its entirety and replaced with the following:

> "The location and transmission adders proposed during the proceeding do not represent actual costs that would be avoided by the utilities."

kkk. FOF 33 on page 113 is modified to read:

> "No statutory provision requires us to consider a set aside for a particular technology."

lll. The second sentence of FOF 34 on page 113 is modified to read:

> "In the interest of administrative efficiency, the two separate schedules should no longer be retained."

mmm. COL 1 on page 115 is modified to read:

"In implementing the amendments to the § 399.20 FiT Program, we rely on federal law, specifically, avoided cost under PURPA, the language of § 399.20 and state laws governing statutory construction, and the policy guidelines adopted herein."

nnn. COL 2 on page 115 is modified to replace "avoided costs pricing" with "avoided cost pricing."

ooo. COL 3 on page 115 is modified to read:

"Based on the *FERC Clarification Order*, the Commission can determine a different avoided cost, differentiated for particular sources of energy based on state procurement requirements."

ppp. The first sentence of COL 7 on pages 115-116 is modified to replace "no longer tied to the MPR" with "no longer required to be tied to the MPR."

qqq. COL 13 on pages 116-117 is modified to read:

"The methodologies presented to determine certain adders, such as those based on technology specific generation, are largely based on general avoided societal costs, not avoided utility costs, and are therefore not the type of avoided costs permitted under PURPA."

rrr. COL 14 on page 117 is modified to delete "and not ratepayer costs,."

sss. The second sentence of COL 15 on page 117 is modified to read:

"The plain language of § 399.20 does not require that technology-specific costs be included in a FiT Program price methodology."

ttt. COL 23 on pages 118-119 is modified to replace "renewable distributed generation" with "renewable generation."

uuu. COL 25 on page 119 is modified to replace "two month's" with "two months'."

vvv. COL 31 on page 119 is modified to replace "§ 399.20(d)(3)" with "§ 399.20(d)(4)."

www. COL 32 on page 120 is modified to read:

"In order to comply with § 399.20(f), the utilities should make their respective tariffs, which incorporate any program requirements required by statute or by the Commission, available on a first-come-first-served basis."

xxx. COL 41 on page 121 is modified to read:

"There is no statutory requirement requiring technological set-asides for the § 399.20 Program. No set-aside (or carve-out) of capacity for specific technologies should be adopted at this time because it is not required by statute or consistent with our policy guidelines for the FiT Program."

yyy. COL 56 is added as follows:

"Any location or transmission adder must be based on costs that are found to be actually avoided by the utilities."

zzz. COL 57 is added as follows:

"§ 399.20(f) discusses the obligation of the utilities to offer their tariffs on a first-come-first-served basis, and does not discuss the Commission's authority to impose pricing, procurement, or other program requirements for the FiT."

aaaa. COL 58 is added as follows:

"The Commission has broad authority over public utilities, including authority over the utilities' resource portfolios and procurement planning, and in implementing the RPS Program. The Commission has the authority to act even in cases where there is no express statutory authorization so long as the additional power and jurisdiction the Commission

exercises are cognate and germane to the regulation of public utilities, and do not contravene or disregard an express legislative directive."

bbbb. The third sentence of OP 6 on page 125, beginning with "This provision shall permit generators…" is modified to insert "in" before "the Commission's Rules of Practice and Procedure."

cccc. The first sentence of OP 7 on page 125, beginning with "Within 90 days…" is modified to insert "the" before "Renewable Auction Mechanism."

dddd. The third sentence of OP 8 on page 126, beginning with "Such a provision…" is modified to insert "the" before "January 10, 2012 ALJ ruling."

eeee. The last sentence of OP 11 on page 127, beginning with "The Commission will review…" is modified to replace "the provision" with "these provisions."

2. A conformed version of D.12-05-035, which incorporates all the modifications made in this order, is attached hereto as Attachment A.

3. Rehearing of D.12-05-035, as modified, is denied.

4. The District's rehearing application is rejected for failing to meet the requirements of Public Utilities Code section 1732.

This order is effective today.

Dated January 24, 2013 at San Francisco, California.

MICHAEL R. PEEVEY
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
MARK J. FERRON
CARLA PETERMAN
Commissioners

EXHIBIT C

COM/FER/acr/avs/gd2 **Date of Issuance 5/30/2013**

Decision 13-05-034 May 23, 2013

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking To Continue Implementation and Administration of California Renewables Portfolio Standard Program.	Rulemaking 11-05-005 (Filed May 5, 2011)

DECISION ADOPTING JOINT STANDARD CONTRACT FOR SECTION 399.20 FEED-IN TARIFF PROGRAM AND GRANTING, IN PART, PETITIONS FOR MODIFICATION OF DECISION 12-05-035

TABLE OF CONTENTS

Title **Page**

TABLE OF CONTENTS
(Cont'd)

Title **Page**

TABLE OF CONTENTS
(Cont'd)

Title **Page**

DECISION ADOPTING JOINT STANDARD CONTRACT FOR SECTION 399.20 FEED-IN TARIFF PROGRAM AND GRANTING, IN PART, PETITIONS FOR MODIFICATION OF DECISION 12-05-035

1. Summary

This decision orders Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) to revise their Feed-in Tariff (FiT) programs to include a new streamlined standard contract and revised tariffs. The new streamlined standard contract incorporates the FiT program requirements adopted in Decision (D.) 12-05-035,[1] as modified.[2] The terms of the standard contract and the provisions of the related tariff are adopted herein and will be implemented through a Tier 2 advice letter filing.

The FiT program is established pursuant to Pub. Util. Code § 399.20,[3] as amended, by Senate Bill (SB) 380 (Kehoe, Stats. 2008, ch. 544, § 1), SB 32 (Negrete McLeod, Stats. 2009, ch. 328, § 3.5), and SB 2 of the 2011-2012 First Extraordinary

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[1] D.12-05-035, *Decision Revising Feed-In Tariff Program, Implementing Amendments To Public Utilities Code Section 399.20 Enacted By Senate Bill 380, Senate Bill 32, and Senate Bill 2 1X And Denying Petitions for Modification of Decision 07-07-027 By Sustainable Conservation and Solutions for Utilities, Inc.* ("FiT Decision" or "D.12-05-035.")

[2] In today's decision, the Commission modifies D.12-05-035 in response to two petitions for modification. These petitions for modification are discussed in detail here. The Commission also modified D.12-05-035 in response to several applications for rehearing. The Commission's decision on rehearing is D.13-01-041, *Order Modifying Decision 12-05-035, and Denying Rehearing of Decision, as modified* (issued January 28, 2013, Rulemaking 11-05-005.)

[3] All statutory references are to the Public Utilities Code unless otherwise indicated.

Session (Simitian, Stats. 2011, ch. 1) (SB 2 1X).[4] This decision does not address the recently effective amendments to § 399.20, enacted by SB 1122 (Rubio, Stats. 2012, ch. 612).[5] We will address SB 1122, and modify the FiT program accordingly, in a subsequent decision.

This decision also modifies certain FiT program requirements adopted in D.12-05-035 in response to two petitions for modification. The modifications include changes to the process used by the utilities to determine the amount of megawatts available for subscription for the three product types during each bi-monthly period. This modification and others are further described in the decision.

This proceeding remains open.

2. Background

Today's decision implements a part of the state's Renewables Portfolio Standard Program[6] (RPS program) applicable to smaller renewable generation projects, commonly referred to as distributed generation.[7] Specifically, today's

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[4] The FiT program was first added to the Pub. Util. Code by AB 1969 (Yee, Stats. 2006, ch. 731), effective 2007, which the Commission implemented in D.07-07-027.

[5] SB 1122 requires the Commission, as part of the FiT program requirements, to direct electrical corporations to collectively procure 250 megawatts (MW) from developers of specified categories of bioenergy projects.

[6] § 399.11 *et seq.*

[7] Additional details about the state's RPS program and the Commission's implementation of that program can be found in Decision (D.)12-05-035 at 4-6.

decision focuses on the Feed-in Tariff (FiT) program implemented pursuant to § 399.20.[8]

Section 399.20 declares the Legislature's intent and the policy of the state to encourage electrical generation from small distributed generation that qualifies as an "eligible renewable energy resource" under the RPS program with an effective capacity of three megawatts or less and, among other things, is strategically located[9] and priced to reflect the "value of different electricity products, including baseload, peaking, and as-available."[10] Under § 399.20, utilities have certain "must-take" obligations to electric generators seeking procurement contracts, and every kilowatt hour of electricity a utility purchases from these electric generators counts toward meeting an electrical corporation's RPS procurement quantity requirements, as determined by statute.

The events leading up to today's decision and a brief history of the FiT program follow.

2.1. Feed-In Tariff Program – D.07-07-027 and D.12-05-035

The Commission first addressed the FiT program in July 2007 in D.07-07-027.[11] In D.07-07-027, the Commission implemented Assembly Bill

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[8] All references to § 399.20 are to that section as amended by Senate Bill (SB) 380 (Stats. 2008, ch.544), SB 32 (Stats. 2009. ch.328), and SB 2 1X (2011-2012 First Extraordinary Session, Stats. 2011, ch.1) unless otherwise noted.

[9] *See* § 399.20(a) and (b)(1)-(4).

[10] *See* § 399.20(d)(2)(C).

[11] D.07-07-027, in which the Commission implemented AB 1969 for eligible facilities up to 1.5 MW, is discussed in detail in D.12-05-035 at 6-9.

(AB) 1969 and established a FiT program for eligible facilities up to 1.5 MW. In 2012, the Commission issued D.12-05-035 adopting a revised and larger program consistent with SB 380 (Kehoe, Stats. 2008, ch. 544, § 1), SB 32 (Negrete McLeod, Stats. 2009, ch. 328, § 3.5), and SB 2 1X (Simitian, Stats. 2011, ch. 1).[12]

D.12-05-035 adopted new program requirements consistent with the above legislation but did not fully implement the program. The Commission deferred consideration of two components of the FiT program: the terms and conditions of a standard contract (the power purchase agreement or PPA) and the tariffs.[13]

Today's decision addresses these previously deferred components of the program and orders Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) (collectively referred to as utilities or IOUs) to revise their FiT programs to include a streamlined joint standard contract and revised tariffs. The streamlined joint standard contract and tariffs incorporate the FiT program requirements adopted in D.12-05-035, as modified.[14]

To implement the joint standard contract and tariffs, the IOUs are ordered to file a Tier 2 Advice Letter for approval of both 30 days after the effective date of this decision. More details are set forth in Section 7.1 herein.

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[12] The history of the FiT program is also found in D.12-05-035 at 3-9.

[13] D.12-05-035 was subsequently addressed on rehearing by the Commission in D.13-01-041, *Order Modifying Decision 12-05-035, and Denying Rehearing of Decision, as Modified* (issued January 28, 2013, Rulemaking (R.) 11-05-005.)

[14] The provisions of the revised FiT program as set forth in today's decision and in D.12-05-035, as modified.

This decision does not address the recently effective amendments to § 399.20, enacted by SB 1122 (Rubio, Stats. 2012, ch. 612). The Commission will address SB 1122 and modify the FiT program consistent with the recently effective legislation in a subsequent decision.

2.2. Procedural History

In response to a directive from the assigned Commissioner and the Administrative Law Judge (ALJ) to develop a single PPA for the FiT program with uniform provisions for all three IOUs, to the greatest extent possible, the IOUs filed a draft joint standard contract on February 15, 2012.[15] Energy Division held a workshop to discuss the provisions of the draft joint standard contract on February 22, 2012. Parties provided verbal comments on the draft joint standard contract at the workshop and then filed written comments on March 5, 2012.

On March 16, 2012, the IOUs submitted a revised draft to incorporate comments from the parties and proposed their own additional modifications.

On March 20, 2012, the ALJ issued a proposed decision (FiT PD) setting forth initial details for the revised FiT program requirements incorporating the requirements of SB 380, SB 32, and SB 2 1X.[16] The ALJ subsequently ordered the

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[15] This directive is set forth in the Joint Assigned Commissioner's and Administrative Law Judge's Ruling Setting Workshop on a Utility Standard Form Contract for Section 399.20 Feed-In Tariff Program, issued January 10, 2012, R.11-05-005.

[16] *Proposed Decision Revising Feed-In Tariff Program, Implementing Amendments To Public Utilities Code Section 399.20 Enacted By Senate Bill 380, Senate Bill 32, and Senate Bill 2 1X And Denying Petitions for Modification of Decision 07-07-027 By Sustainable Conservation and Solutions for Utilities, Inc.* This proposed decision is available on the Commission's website.

IOUs to update the revised draft joint standard contract to reflect changes consistent with the FiT PD. The IOUs filed this second draft joint standard contract on April 30, 2012.

In response to the FiT PD, the Commission issued a final decision dated May 31, 2012. This final decision, D.12-05-035, differed from the FiT PD. Therefore, on June 26, 2012, the ALJ directed the IOUs to conform the draft joint standard contract to the provisions of D.12-05-035. On the same date, the ALJ directed the IOUs to file draft FiT tariffs. These next filings, dated July 18, 2012, represented the third revised joint standard contract and the first proposed draft tariffs. Parties filed comments on August 15, 2012 and reply comments on August 29, 2012.

On January 7, 2013, the ALJ further directed the IOUs to file revised FiT tariffs to achieve greater uniformity in the provisions found in their respective tariffs. The IOUs filed revised FiT tariffs on January 18, 2013 and parties filed comments on these revisions on January 25, 2013.

Finally, the Commission issued a decision on rehearing of D.12-05-035 on January 28, 2013. This decision, D.13-01-041, modified and denied rehearing of D.12-05-035. To the extent the modifications set forth in D.13-01-041 need to be incorporated into the FiT joint standard contract and the FiT tariffs, we address those modifications herein.

This proceeding remains open and the procedural schedule is included in the January 9, 2013 Scoping Memo Ruling.[17] The implementation of SB 1122 is the Commission's next priority for the FiT program.

3. Policy Guidelines

In D.12-05-035 we established five core policy guidelines to assist us in adopting the revised FiT program requirements.[18] In today's decision, we continue to rely on these five core policy guidelines as we evaluate the merits of provisions of the draft joint standard contract and tariffs. These five policy guidelines are as follows:[19]

1. Establish a feed-in tariff price based on quantifiable ratepayer avoided costs that will stimulate market demand;
2. Contain costs and ensure maximum value to the ratepayer and the utility;
3. Ensure administrative ease and lower transaction costs for the buyer, seller, and regulator;
4. Use existing transmission and distribution infrastructure efficiently; and
5. Establish project viability criteria to increase probability of successful projects within the program.

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[17] *Second Amended Scoping Memo and Ruling of Assigned Commissioner*, dated January 9, 2013, R.11-05-005 at 2 and 6.

[18] D.12-05-035 at 18-19.

[19] In D.12-05-035 at 19, we stated "Overall, we find that these guidelines provide an important secondary source of guidance as we implement SB 320, SB 32, and SB 2 1X. Our primary source of guidance, as stated above, is derived from the rules of statutory construction."

Today's decision applies the above policy guidelines to balance the various interests involved in this proceeding and to achieve reasonable outcomes that facilitate a successful FiT program. We also rely on these policy guidelines to evaluate the merits of two petitions for modification of D.12-05-035. We discuss these petitions for modification below.

4. Petitions for Modification to D.12-05-035

Solar Energy Industries Association (SEIA), California Solar Energy Industries Association (CALSEIA), and Clean Coalition filed petitions to modify of D.12-05-035.[20] These petitions address the revised FiT program requirements adopted in D.12-05-035. PG&E and SCE filed a joint response to SEIA's petition for modification.[21] All three IOUs filed a joint response to CALSEIA's and Clean Coalition's petition for modification.[22] We grant, in limited part, these petitions. In doing so, we modify a few FiT program requirements, including the process

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[20] On July 31, 2012, SEIA filed *Petition of the Solar Energy Industries Association for Modification of Decision 12-05-035*. On November 13, 2012, CALSEIA and Clean Coalition jointly filed *Clean Coalition and California Solar Energy Industries Association Petition for Modification of D.12-05-035*.

[21] On August 30, 2012, PG&E and SCE filed a joint response to SEIA's petition for modification. On August 31, 2012, CALSEIA filed a response in support of SEIA's petition for modification.

[22] On December 12, 2012 the IOUs filed a joint response to CALSEIA's and Clean Coalition's petition for modification, stating at 2: "Just six months after the Commission approved D.12-05-035 and before the new Re-MAT program could even be implemented, Clean Coalition and CALSEIA seek to re-litigate several issues that were thoroughly litigated earlier in this proceeding and decided in D.12-05-035. The Clean Coalition/CALSEIA PFM provides no new information to justify modifying the Commission's earlier determinations."

for IOUs to offer megawatts for subscription. We also clarify, among other things, how megawatts are returned to the FiT program after a project failure and we remove the seller concentration provision from the program viability criteria. Because both petitions request that we modify the FiT program's price-adjustment intervals from bi-monthly to monthly and that we reduce the length of the program from 24 to 12 months, we address these common issues first. Then we turn to the remaining issues raised in the petitions for modification.

4.1. Modified Renewable Market Adjusting Tariff (ReMAT) Mechanism

In response to the petitions for modification, we find that the megawatt allocation process adopted in D.12-05-035 for PG&E, SCE, and SDG&E may hinder the advancement of the program because it may result in too few megawatts being offered during each bi-monthly program period. In some cases, as SEIA, Clean Coalition, and CALSEIA recognize, less than one megawatt would be offered for each product type per bi-monthly program period under the process adopted in D.12-05-035.[23]

Accordingly, we modify, in part, the process for offering the FiT program megawatts.[24] We retain the bi-monthly price-adjustment intervals but increase the total number of megawatts that the IOUs must offer for each product type[25]

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[23] SEIA petition for modification at 3; CALSEIA and Clean Coalition petition for modification at 3.

[24] D.12-05-035 (Section 6.5) at 49-50.

[25] The term product type is described in D.12.05-035 when the Commission ordered the IOUs to assign an equal portion of their allocated capacity to three product types, i.e.,

Footnote continued on next page

in each bi-monthly program period.[26] We also adopt changes to the program to contain costs.[27]

D.12-05-035 allocated the total available program megawatts among the three IOUs in proportion to their percentage share of retail sales, as required by § 399.20.[28] We do not change this aspect of D.12-05-035 today. D.12-05-035 further ordered the IOUs to assign an equal portion of their program's megawatts to three product types, i.e., baseload, peaking as-available, and non-peaking as-available.[29] We do not change this aspect of D.12-05-035 today.

D.12-05-035 then ordered the IOUs to equally assign their megawatts to 12 two-month program periods and offer one-twelfth of the available megawatts (distributed among the three product types) for subscription each bi-monthly

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baseload, peaking as-available, and non-peaking as-available. D.12-05-035 (Section 6.5) at 49-50; § 399.20(d)(2)(C).

[26] In response to comments to the March 19, 2013 proposed decision filed by PG&E, SDG&E, SCE, DRA, and TURN on April 8, 2013 and April 15, 2013, we revise the proposed decision to decrease the recommended allocation of 10 MW to 5 MW for PG&E and SCE and to 3 MW for SDG&E to address concerns that, under a 10 MW allocation framework, the FiT price would never reach equilibrium, that it would be very hard for the price to decrease and easy to increase, and therefore would fail to "minimize ratepayer exposure to a large number of non-competitively priced contracts while ensuring that some capacity is available for each product type…" (D.12-05-035 at 51).

[27] PG&E April 8, 2013 comments at 2.

[28] D.12-05-035 (Section 12.3) at 74-77 and D.13-01-041 at 16-18 (the FiT allocation process for megawatts adopted in D.12-05-035 is clarified on rehearing).

[29] D.12-05-035 (Section 6.5) at 49-50; § 399.20(d)(2)(C).

program period.[30] Under D.12-05-035, in the event that the offered megawatts were unsubscribed in a program period those unsubscribed megawatts rolled forward to Months 25-26.[31] Today, we modify these aspects of the program in an effort to make a more workable amount of megawatts available during each bi-monthly program period.

We modify D.12-05-035 to direct PG&E and SCE to offer 5 MW for each of the three product types for each bi-monthly program period until the available megawatts for that product type falls below 5 MW. SDG&E must offer 3 MW per product type in each bi-monthly program period because the size of SDG&E's program is smaller than PG&E's and SCE's. The IOUs must continue to offer the remaining megawatts for the product type until the megawatts go to zero or the program ends as described below.

In addition, we modify two aspects of the program to protect against unreasonable price increases. We establish a cap on the total price period adjustment at $12 to avoid excess bi-monthly price adjustments.[32] We also change the threshold for triggering a price increase in a subsequent program period to less than 20%, rather than 50%, of capacity for the current period.[33]

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[30] D.12-05-035 at 49-50; D.13-01-041 at 16-18 (the FiT megawatt allocation process for megawatts adopted in D.12-05-035 is clarified on rehearing).

[31] D.12-05-035 at 49-50; D.13-01-041 at 16-18 (the FiT MW allocation process adopted in D.12-05-035 is clarified on rehearing).

[32] DRA April 8, 2013 comments at 4-5, DRA points out that cap may reduce ratepayer costs due to overpriced contracts.

[33] PG&E April 8, 2013 comments at 3-4.

Also, as a result of this change to the megawatt allocation rules, in combination with the determination in Section 4.4 herein, we find it reasonable to change a condition used to determine whether a price adjustment will be triggered. In D.12-05-035, we established conditions for a price adjustment, including one tied to the level of program subscription in a bi-monthly program period. For example, the condition for a price decrease was if subscription equaled 100% or more of the initial capacity allocation for a product type. However, by not allowing subscriptions to exceed the megawatts offered in a bi-monthly program period (as discussed in Section 4.4 herein), it is likely that subscription will fall below 100% subscription even if the market demand exceeds that amount, and thus no price adjustment will be triggered (5 MW for PG&E and SCE, 3 MW for SDG&E). This change, described below, will more appropriately tie the price adjustment mechanism to market demand, which is better reflected by the applicants that express willingness to execute a PPA at an applicable ReMAT price, rather than the applicants that are awarded ReMAT PPAs.

As modified today, a price decrease adjustment will be triggered if the total capacity of the projects for which applicants have indicated that they would be willing to execute a ReMAT PPA based on the applicable contract price for a period is at least 100% of the capacity allocation for that period (i.e., 5 MW or less only if the available capacity for that product has fallen below a total of 5 MW, or 3 MW or less for SDG&E).

Also, as modified today, a price increase adjustment will be triggered if the total capacity of the projects for which applicants have indicated a willingness to execute a ReMAT PPA based on the applicable contract price for a period is less than 20% of the capacity allocation for that period.

Also, as modified today, a price will remain unchanged in the subsequent bi-monthly period if the total capacity of the projects for which applicants have indicated that they would be willing to execute a ReMAT PPA based on the applicable contract price for a period is at least 20% of the capacity allocation for that period but a price decrease has also not been triggered.

Under today's approach, the duration of the program remains fixed but we modify D.12-05-035 to establish the end date at 24 months after the first product type goes to zero MW or goes to a *de minimis* amount approaching zero.[34] An end date for the program is important because, otherwise, the program could go into perpetuity with a minuscule amount of megawatts being offered each bi-monthly period.[35] An end date also promotes administrative ease by defining the length of time the Commission and the utilities must dedicate resources to this program.[36]

Moreover, consistent with D.12-05-035, we clarify that each IOU must publicly notice on the first business day of each bi-monthly program period[37] the number of megawatts offered for each product type during that bi-monthly

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[34] PG&E April 8, 2013 comments at 4.

[35] PG&E April 8, 2013 comments at 4.

[36] PG&E April 8, 2013 comments at 4.

[37] The IOUs shall also make this information public on the date that the revised standard contracts and tariffs become effective so that the market is aware of the program size at the commencement of the revised FiT program.

program period, the number of megawatts remaining for each product type, and the total number of megawatts remaining in the IOU's FiT program.[38]

Accordingly, PG&E and SCE must offer 5 MW and SDG&E must offer 3 MW at the start of each bi-monthly program period for each product type unless less than 5 MW are available for a particular product type for PG&E and SCE and less than 3 MW are available for a particular product type for SDG&E, in which case, the IOU must offer all remaining megawatts for the product type. Any megawatts remaining at the end of a program period will be retained within the same product type. The total price adjustment will be capped at $12. The threshold for triggering a price increase will be less than 20% of capacity for the current period. The price adjustment mechanism will, in part, be triggered by the amount of capacity associated with the applicants providing notice to the IOU of their willingness to accept the offered price. Each IOU shall publicly notice the amount of megawatts offered and remaining for each bi-monthly program period, in addition to other existing notice requirements. The IOU's program will end 24 months after the capacity for a product type reaches zero or approaches a *de minimis* amount.

4.2. Additional Modifications Proposed by SEIA

We now address the remaining issues raised by SEIA in its petition for modification. SEIA suggests that the Commission modify D.12-05-035 as follows:

(1) specify how megawatts are placed back into program due to, for example, contract termination;

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[38] D.12-05-035 at 49.

(2) allow contracts for amounts above the allotted megawatts when the last project in the queue results in exceeding bi-monthly megawatt allocation;

(3) change the megawatt allocation process because, consistent with the first-come, first-served program requirement, the IOU must offer a contract to a developer even if the IOU has exceeded its bi-monthly megawatt allocation;

(4) elaborate on the meaning of "PPR [Program Participation Request] is deemed completed"[39] in D.12-05-035 because this event triggers a critical event, the designation of a project's FiT program number, so if more than one PPR is "deemed complete" by the IOU on the same day the IOU should determine the FiT program number by the project's interconnection queue position;

(5) remove the restriction on participation in the Renewable Auction Mechanism (RAM) program because smaller solar projects (3 MW and under) cannot bid into RAM and very few megawatts are available in the FiT program;[40]

(6) permit developers to choose to interconnect to the distribution system under Electric Tariff Rule 21 or the federal wholesale tariffs, known as WDAT,[41] or, alternatively, permit developers now interconnecting

[39] A "Program Participation Request" is the request used by applicants to establish eligibility to participate in an IOU's FiT program. This process is described in the FiT tariff.

[40] RAM or the Renewable Auction Mechanism is a Commission program adopted in D.10-12-048 and subsequently modified by numerous Commission resolutions.

[41] The term "WDAT" is used herein to refer to the IOUs' federal wholesale interconnection FiT tariffs.

under WDAT to continue to complete the process under WDAT; and

(7) remove the seller concentration provision[42] from the FiT Project Viability Criteria because the definition is unclear and seller concentration is not a problem due to the inclusion of three product types.

We address each of these issues below.

4.3. Adding Megawatts Back into FiT Program

In response to the first issue, we modify D.12-05-035 to clarify how megawatts are added back into the FiT program after a change in circumstances, including, but not limited to, the termination of a project. SEIA suggests that megawatts from terminated projects should be added to the total megawatts available to each IOU. SEIA's suggestion is similar to the IOUs' proposal.

The IOUs propose the following language to address "terminated" megawatts in their January 18, 2013 draft tariffs:

> Any capacity associated with CREST, WATER, or Re-MAT PPAs that are terminated prior to delivering electricity during the Initial Program Phase will be allocated by SCE to one or more Product Types and Periods beginning in an Initial Program Phase Period that has less than the Initial Allocation (or the 3 MW minimum) or to the Second Program Phase. Any capacity associated with CREST, WATER, or Re-MAT PPAs

[42] The seller concentration provision adopted in D.12-05-035 is discussed in more detail later and generally provides for seller concentration limit of 10 MW per seller.

> that are terminated after delivering electricity or during the Second Program Phase will not be re-allocated.[43]

We find merit in the IOUs' proposal but find that the IOUs should revise the above to clarify that megawatts procured through the revised FiT program are placed back into the product types of the terminated project. IOUs should remove the restriction on adding megawatts back into the program after the second program Phase as this decision eliminates a separate Second Program Phase. In adopting this process, we seek to reasonably balance our goal of administrative ease and transparency with the goal of creating opportunity for developers to create successful projects. This process will not apply to projects terminated after delivery of electricity begins due to the numerous transactional complications that could arise. The megawatts from these projects will not be added back into the program. Projects governed by the FiT program under D.07-07-027 and AB 1969 do not include product types. Therefore, if a project is terminated that was initiated when the FiT program was solely governed by D.07-07-027 and AB 1969, those megawatts will be placed back into the IOU's total program megawatts to be equally divided among all three product types.

This request for modification of D.12-05-035 is granted.

4.4. Subscriptions May Not Exceed the Amount of Megawatts Offered During a Bi-Monthly Period

D.12-05-035 did not address either the second or third issue listed above. SEIA seeks clarification of these issues in both its petition for modification and in comments on the IOUs' July 18, 2012 draft tariffs. SEIA states that the

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[43] SCE's January 18, 2013 draft tariff at section G(5).

Commission should permit the IOUs to accept a bid if that bid meets but then exceeds the megawatts allocated to a product type within a bi-monthly program period by pulling extra megawatts from a later program period. In response to the SEIA's request, and as explained further here, we clarify that no subscriptions will be permitted above the number of megawatts offered for a product type within any bi-monthly program period.

In contrast to SEIA's suggestion, PG&E's July 18, 2012 draft tariff provides that requests for contracts that exceed the megawatts allocated to a product type within bi-monthly period will not be accepted. The relevant language from PG&E's July 18, 2012 draft tariff provides:

> If the Contract Capacity of the next Applicant, in Queue Number order, for a Product Type is larger than the remaining Bi-Monthly Product Type Allocation, the Bi-Monthly Product Type Allocation will be deemed to be fully subscribed.

In other words, PG&E's July 18, 2012 draft tariff states that if insufficient megawatts exist in the product type allocation for that bi-monthly program period, then the IOU will not award a contract to the next project in the queue and the IOU will not accept any additional subscriptions for that product type during that bi-monthly program period. SCE's July 18, 2012 draft tariff has a comparable provision. SDG&E's July 18, 2012 draft tariff is unclear on this matter.

The IOUs' January 18, 2013 draft tariffs present a uniform provision on this topic that retains the restriction on bids for amounts above the remaining allocated megawatts. The relevant provision from SDG&E's January 18, 2013 draft tariff follows:

> If the Contract Capacity of the next Project, in Re-MAT Queue Number order, for a Product Type is larger than the remaining Available Allocation, that next Applicant will not be awarded a Re-MAT PPA and SDG&E will deem the Available Allocation to be fully subscribed (Deemed Fully Subscribed).

D.12-05-035 did not address this issue. Today, we adopt a limit on the amount of megawatts available in a product type during a bi-monthly period. We find that the proposal set forth in the IOUs' January 18, 2013 tariffs is reasonable. While this limit may result in developers having to wait and then decide whether to request a contract at the offered rate in the next bi-monthly program period, we find that this result reasonably balances the goals of providing transparency and guidance to the market with the goal of providing sufficient opportunity for developers.

Furthermore, we find that the first-come, first-served program requirement[44] does not mean that the IOU must accept a request for a contract if insufficient megawatts remain in a product type for the bi-monthly program period.[45] The Commission has authority to structure the program within the guidelines provided by the statute. This result reasonably balances our goal of creating a clear and administratively enforceable means of establishing when a

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[44] § 399.20(f).

[45] Clean Coalition argues that the IOUs will violate the first-come, first-served provision if they fail to offer a contract to the next project in line even if that project exceeds the megawatt cap for a product type within a bi-monthly period. Clean Coalition September 10, 2012 comments at 8-9.

product type in a bi-monthly program period has been fully subscribed with the goal of providing developers with opportunities for successful projects.

Accordingly, D.12-05-035 is modified as set forth above and we adopt the proposed language as set forth in the January 18, 2013 draft tariffs. This request for modification of D.12-05-035 is denied.

4.5. Interconnection Queue Position not Relevant to FiT Program Number

In response to the fourth issue above, we find that no further elaboration is warranted on the term "deemed completed" in D.12-05-035 when referring to a PPR.[46] We also reject SEIA's request that the FiT program number be determined by the project's interconnection queue position if more than one PPR is "deemed complete" by the IOU on same day.[47]

D.12-05-035 states that: "Once the participation request form is deemed complete, the IOU will establish a queue on a first-come, first-served basis for each product type."[48] We recognize that this language permits the IOUs to establish their own internal method of determining how a PPR is "deemed complete." We find that while this process is not entirely transparent, the first-come, first-served statutory mandate provides enough guidance to the IOUs to ensure a fair process. In addition, the IOUs elaborate on this process in their tariffs. Moreover, we find that this process must be implemented based on date

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[46] D.12-05-035 at 45.

[47] Clean Coalition raises the same issue in its comments on the IOUs' July 18, 2012 draft tariffs. Clean Coalition September 10, 2012 comments at 3.

[48] D.12-05-035 at 45.

and time of PPR submittal; not on a project's position in the interconnection queue. The incorporation of the queue position adds an unduly complicated additional administrative component to the program.

We find one exception to this principle. This exception is narrow and properly tailored to effectuate the goal of the statutory language while also minimizing confusion when the program is first open to receipt of PPRs. We recognize the likelihood of significant market response on the first day of the program and find that assigning queue numbers based on the exact date and time of the PPR may present significant administrative and technical challenges should there be any issues with the IOUs application process.[49] The IOUs will be implementing web-based software program to process the PPR and while this software should be user-friendly, some difficulties may arise.[50] To minimize the impact of any technical concerns, those applications received within the first five business days of the program will be deemed received at the same time and their program number will be assigned by lottery or otherwise on a random basis.[51]

Accordingly, we find no further directive to the IOUs on this topic is warranted. We will address this matter further if actual problems arise. This request for modification is denied.

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[49] PG&E April 8, 2013 comments at 6-7.

[50] PG&E April 8, 2013 comments at 6-7.

[51] PG&E April 8, 2013 comments at 6-7.

4.6. RAM Participation Restriction is Retained

In response to the fifth issue above, we do not remove the restriction on participating in the RAM program. D.12-05-035 prohibits a project with a nameplate capacity of 3 MW or less from participating in RAM if the project meets other eligibility criteria for the FiT program, and if the capacity for the relevant FiT product type has not yet been reached.[52] We adopted this restriction to guard against gaming between the two programs and to promote administrative efficiency by eliminating substantially similar duplicative procurement mechanisms for these projects. Our concerns remain the same. We note that there is no similar restrictions in the RPS annual solicitations or related to bilateral contracts with an IOU.

Accordingly, as clarified above, we make no change to this aspect of D.12-05-035. This request for modification is denied.

4.7. Interconnection under Federal Wholesale Tariffs or Electric Tariff Rule 21 – Generator's Choice

In response to the sixth issue above, we clarify our intent in D.12-05-035 to provide developers with a choice of the federal or state interconnection tariffs.

SEIA requests that we clarify our statement in D.12-05-035 that "…until the Commission makes a final determination in R.11-09-009…utilities shall allow generators to choose which interconnection processes to use, either the process set forth in Rule 21 Tariff or WDAT."[53] Clean Coalition, IREC, and SEIA point

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[52] D.12-05-035 at 67-69.

[53] D.12-05-035 at 100.

out that this same issue appears in the July 18, 2012 draft tariffs and requires clarification.

Accordingly, today we clarify that our statement in D.12-05-035 means that if both federal and state interconnection tariffs are applicable in a given situation, the developer is permitted to choose whether to proceed under Electric Tariff Rule 21 or the federal tariffs, until the Commission makes a determination otherwise.

4.8. Seller Concentration Provision is Removed from Project Viability Criteria

In response to the seventh issue above, we remove the seller concentration provision from the FiT program's Project Viability Criteria adopted in D.12-05-035. D.12-05-035 provides for a seller concentration limit of 10 MW per seller and states that "[t]he definition of seller should be further explored in the standard contract phase of this proceeding."[54]

The Commission adopted a seller concentration limit of 10 MW per seller in D.12-05-035 to facilitate participation in the FiT program by different developers.[55] In adopting the seller concentration limit, the Commission recognized that it would need to address additional details related to the seller concentration before implementation and stated that the Commission would revisit the definition of seller concentration when reviewing the IOUs' draft standard contracts.[56]

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[54] D.12-05-035 at 69-70.

[55] D.12-05-035 at 69-70.

[56] D.12-05-035 at 70.

Now, upon further review of the seller concentration limit, we find merit in SEIA's proposal to remove it. We find that implementation of a seller concentration limit as a Project Viability Criterion is a complex undertaking. Furthermore, we agree with SEIA that, at least for now, our reliance on three product types provides sufficient opportunity for different market segments to participate in the FiT program.

Accordingly, we remove the seller concentration limit from the Project Viability Criteria. This request for modification of D.12-05-035 is granted.

4.9. Additional Modifications Proposed by CALSEIA and Clean Coalition

We now address the remaining issues raised by CALSEIA and Clean Coalition in their petition for modification. They suggest that the Commission modify D.12-05-035 as follows:

(1) add additional megawatts to the FiT program above the amount set forth in § 399.20;

(2) include a price floor in the FiT pricing mechanism;

(3) include a locational adder (as referenced in § 399.20(e)) to the price to capture the benefits of grid planning and procurement methodology;

(4) add environmental compliance costs to the price, as set forth in § 399.20(d)(1);

(5) refine the definition of "strategically located," as referenced in § 399.20(b)(3) to, among other things, account for a piece of equipment sometimes

needed for interconnection of a project, a Direct Transfer Trip;[57] and

(6) extend the Commercial Operation Date (also referred to as the COD) due to unpredictable interconnection delays.

We address each of these issues below.

4.10. No Increase in the Program's Total Megawatts

In response to the first issue above, we do not modify D.12-05-035 to increase the overall number of megawatts in the FiT program. Instead, we seek to address the concerns raised by CALSEIA and Clean Coalition related to the limited number of total megawatts in the FiT program by increasing the capacity offered for each product type during each bi-monthly program period to 5 MW for PG&E and SCE, and to 3 MW for SDG&E, as described above in Section 4.1 herein.

This request for modification is denied.

4.11. No Price Floor

In response to the second issue above, we do not adopt CALSEIA's and Clean Coalition's request that we modify D.12-05-035 to adopt a price floor. Clean Coalition raised this issue in its April 9, 2012 comments and its April 16, 2012 reply comments to the FiT PD.

In its April 16, 2012 comments, Clean Coalition wrote:

> A price cap should, however, be paired with a price floor, set at the normalized RAM clearing price, as we recommended in

[57] This term is found in CALSEIA and Clean Coalition petition for modification at 15.

> our opening comments. The price cap ensures that ratepayers are not made to pay beyond a certain level for SB 32 projects; the price floor ensures that the "race to unviability" will be avoided and allow developers to plan ahead with the certainty that the contract price will never fall below a certain level.[58]

Clean Coalition and CALSEIA provide no new information now. When Clean Coalition raised this issue in the past, the Commission did not adopt this recommendation because the FiT program already incorporates several mechanisms to guard against unreasonably low pricing.

This request for modification is denied.

4.12. No Change to Locational Adder, Strategically Located, or Environmental Compliance Costs

In response to the third, fourth, and fifth issues above, we first point out that the term called "locational adder" is often used to refer to different concepts. The term is sometimes used to refer to the costs described in § 399.20(e), which are correctly "locational adders."[59] The term is also used to convey the concept captured in § 399.20(b)(2), which is more appropriately known as "strategically located."[60] At other times, the term is used to refer to the costs described in § 399.20(d)(1), which are instead "environmental compliance costs."[61]

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[58] Clean Coalition April 16, 2012 comments at 3-4.

[59] § 399.20(e) states, in part: "The commission shall consider and may establish a value for an electric generation facility located on a distribution circuit that generates electricity at a time and in a manner so as to offset the peak demand on the distribution circuit."

[60] § 399.20(b) states, in part: "As used in this section, "electric generation facility" means an electric generation facility located within the service territory of, and developed to

Footnote continued on next page

CALSEIA's and Clean Coalition's petition for modification requests additional Commission action on all three topics: locational adder, strategically located, and environmental compliance costs. We address these three topics below.

Regarding locational adders, the Commission is working toward developing a methodology to value avoided transmission and distribution costs, if possible. The Commission's Energy Division held a workshop in R.11-05-005 related to this topic on January 31, 2013 and will continue to work on this matter. More information on this topic will be provided later in the proceeding.[62]

Regarding "strategically located," today's decision confirms our previously adopted definition of strategically located in D.12-05-035.[63] We

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sell electricity to, an electrical corporation that meets all of the following criteria:…(3) Is strategically located and interconnected to the electrical transmission and distribution grid in a manner that optimizes the deliverability of electricity generated at the facility to load centers."

[61] § 399.20(d)(1) states: "The tariff shall provide for payment for every kilowatthour of electricity purchased from an electric generation facility for a period of 10, 15, or 20 years, as authorized by the commission. The payment shall be the market price determined by the commission pursuant to paragraph (2) and shall include all current and anticipated environmental compliance costs, including, but not limited to, mitigation of emissions of greenhouse gases and air pollution offsets associated with the operation of new generating facilities in the local air pollution control or air quality management district where the electric generation facility is located."

[62] Clean Coalition alleges that the Commission failure to adopt a location adder is a violation of SB 32 in its April 8, 2013 comments at 15. The Commission disposed of this allegation in D.13-01-041 at 12-14 stating, "Clean Coalition/Sierra Club allege that the Decision violates this provision of SB 32 by failing to adopt a location or transmission adder. (Clean Coalition/Sierra Club Rehrg. App., pp. 5-6.) This allegation lacks merit."

[63] D.12-05-035 (Section 6.9) at 56.

continue to find that our definition of strategically located appropriately balances the goal of using the existing transmission and distribution system efficiently and containing costs while ensuring maximum value to ratepayers with making the program as accessible as possible for developers. Our definition is consistent with Section 14.9.2 of the draft joint standard contract which is designed to address the situation where the seller's interconnection study showed transmission network upgrades of $300,000 or less but that such costs subsequently exceed $300,000 after execution of the contracts.[64] In these circumstances, the seller can buy-down its transmission network upgrades in excess of $300,000 to avoid termination of the contract. This provision does not permit sellers whose interconnection studies or agreements show they have more than $300,000 in transmission network upgrades before they receive a contract to be eligible for the FiT program as such a change would render "strategically located" meaningless.

Regarding environmental compliance costs, the Commission found in D.13-01-041, that "…because the Re-MAT is a market-based price, it should include all of the generator's costs, including current and anticipated environmental compliance costs."[65] In other words, the ReMAT[66] pricing

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[64] Several parties address the interplay between Section 14.9.2 of the draft joint standard contract and the definition of strategically located in D.12-05-035, including Clean Coalition April 8, 2013 comments at 16; Placer District April 8, 2013 comments at 6-7, SCE April 15, 2013 comments at 3-4.

[65] D.13-01-041 at 6.

[66] The term ReMAT is an acronym for "Renewable Market Adjusting Tariff" and refers to the pricing methodology adopted for the revised FiT program. (D.12-05-035 at 38.)

structure theoretically includes all costs incurred by a generator, including the generator's environmental compliance costs. As such, the issue raised by CALSEIA and Clean Coalition is now resolved.

The petition for modification by CALSEIA and Clean Coalition is denied.

4.13. No Further Extension to the Commercial Operation Date; Single 6-Month Extension Permitted

In response to the sixth issue above, we do not extend the COD based on Clean Coalition's and CALSEIA's claims related to unpredictable interconnection delays. As adopted in D.12-05-035, the COD includes 24 months and a 6-month extension.[67] Requests to extend and then further extend the COD have been made numerous times in this proceeding. Clean Coalition raised this matter in its April 16, 2012 reply comments to the FiT PD issued prior to D.12-05-035.[68] Clean Coalition and CALSEIA present no new information now. We do not reconsider this matter again today. We do, however, find it reasonable to require the IOUs to modify the draft joint standard contract to change from the day-for-day extension for a maximum of 6 months to a single 6-month extension and include an obligation for sellers to provide documentation to demonstrate that the seller did not cause the delays at issue.[69]

Clean Coalition's and CALSEIA's request for modification of the COD is denied, except as pertaining to the single 6-month extension.

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[67] D.12-05-035 at 70.

[68] Clean Coalition April 16, 2012 comments at 6-7.

[69] Clean Coalition April 8, 2013 comments at 25-26; SEIA April 8, 2013 comments at 2.

5. FiT Joint Standard Contract - Power Purchase Agreement

The parties in this proceeding achieved a major goal.[70] They worked diligently to create one contract for the FiT program to be used by all three IOUs. The majority of the terms in the joint standard contract apply to all three IOUs. While parties made great strides in reaching consensus on numerous contract topics, the IOUs did not agree to all terms. Any differences among the IOUs are captured and specifically noted within the joint standard contract. The discussion below at Section 6 identifies and resolves areas of dispute among the parties and is organized by the separate contract sections. First, however, we address several overarching issues regarding the terms and condition of the draft joint standard contract.[71]

5.1. Length of Contract is Reasonable

Clean Coalition claims that, contrary to the intent of SB 32, the draft joint standard contract represents an increase in complexity and burden when compared with the previously existing contracts under the FiT program.[72]

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[70] The joint single contract was formed in response to a directive from the Assigned Commissioner and ALJ. This directive is set forth in the *Joint Assigned Commissioner's and Administrative Law Judge's Ruling Setting Workshop on a Utility Standard Form Contract for Section 399.20 Feed-In Tariff Program*, issued January 10, 2012, R.11-05-005.

[71] SCE notes in comments filed on April 15, 2013 that, in compliance with D.13-02-004 at 41 (Ordering Paragraph 2), SCE must incorporate a term into the joint standard contract (applicable only to SCE) that addresses certain matters pertaining to the closure of the Mohave Generating Station and the Hopi Tribe.

[72] Clean Coalition September 10, 2012 comments at 2-3.

We find the joint standard contract to be a reasonable length. As we stated above, the draft joint standard contract is lengthier than the previously existing contract because all relevant materials, such as attachments and forms, for each IOU are combined into one single document. As a result, the overall length of the contract increased but the benefits of a single joint standard contract instead of three separate contracts are significant.

These benefits include, among others, that developers and regulators will be able to source information in the joint standard contract quickly by referring to a single document rather than multiple documents. Developers and regulators will no longer have to cross-reference three separate contracts to compare contract details, which is cumbersome and time-consuming. As regulators, we will be able to respond more efficiently to questions from the public regarding the status of, for example, a particular provision of the joint standard contract as all the materials will be found in a single document.

We are not persuaded by Clean Coalition's claim that the contract is too complex for small developers. The projects eligible for the FiT program may be smaller than other projects in this industry but FiT projects still generate significant revenues. For instance, a 1.5 MW project could generate a revenue stream of approximately $7 million.[73] This level of revenue requires a relatively sophisticated contract to ensure proper administration of the transaction.

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[73] For example, $7,003,271 in gross revenue could be expected based on the $89.23/MWh starting price for ReMAT with a 1.5 MW project, averaging 3.92 GWh/year of generation which, over a 20 year contract term, would be 78.49 GWh (or 78,486 MWh) (which is pre-Time-of-Delivery).

5.2. Clarify Function of a Commission-Approved Standard Contract

In response to questions raised by parties regarding the purpose of a standard contract, we clarify the difference between standard contracts and other contracts relied upon in the RPS program. Our explanation includes describing the streamlined nature of standard contracts.

The Commission's programs implemented under or in support of the RPS program, including FiT, rely upon contracts to memorialize the purchase of renewable energy. In some circumstances, such as the contracts executed as a result of the annual RPS solicitations, the terms and conditions of these contracts are negotiable, with the exception of specific terms required by the Commission. After these contracts are executed, parties must obtain Commission approval of the terms and conditions.

In contrast, the FiT program relies upon a standard contract.[74] These contracts are referred to as "standard" contracts because, among other reasons, the same form contract is offered to all eligible developers and the Commission pre-approves the terms and conditions of a standard contract for the later use by parties. This pre-approval process includes the finding by the Commission that the IOUs are entitled to full cost recovery through rates for these Commission-approved contracts. Therefore, parties are not required to obtain

[74] The Commission's use of a standard contract for the FiT program is supported by § 399.20(g), which provides the Commission with the option of using standard contracts for the FiT program.

approval from the Commission after executing the contract, which could be a time consuming process.

For this reason, standard contracts inherently represent a streamlined process. The Commission's use of a standard contract for the FiT program is one means used by the Commission to streamline the FiT program as standard contracts eliminate the need to seek Commission approval after a deal is finalized. This process is ideal for the FiT program because smaller developers have, perhaps, more limited resources to devote to the process of obtaining contract approval from the Commission.

Importantly, to the extent parties agree to terms and conditions that differ from the Commission-approved standard contract, parties will need to seek approval of the contract from the Commission.[75]

5.3. Clarify Meaning of "Standard Terms and Conditions" and "Non-Modifiable" Terms

We also clarify the meaning of "standard terms and conditions," also known as STCs, and of "non-modifiable," as referred to in the joint standard contract. In D.07-07-027, the Commission discussed the merits of adopting, in whole or in part, "standard terms and conditions" or STCs for the FiT program. STCs include contract provisions adopted by the Commission for the power purchase agreements used by the broader RPS program.[76]

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[75] As stated in D.07-07-027, "A seller may elect to engage in negotiations, but the resulting deal would then be a bilateral or other type of contract, and outside the scope of the § 399.20 tariff/standard contract program." D.07-07-027 at 8.

[76] D.04-06-014 as modified by D.07-02-011 and D.07-05-057, D.08-08-028, D.10-03-021 and D.11-01-025 (decisions addressing STCs in the context of the RPS program).

In D.07-07-027, the Commission incorporated many of these STCs in the FiT contract.[77] Some of these STCs are "non-modifiable," meaning that a change to those terms is only permissible in limited circumstances, which are not relevant here because the FiT contract is a standard contract not subject to change without Commission approval.[78]

However, to clarify these concepts in the FiT joint standard contract, PG&E, SCE, and SDG&E are directed to make the below modification to the July 18, 2012 draft joint standard contract. On page (i) of the draft joint standard contract, above the name of the contract and in highlighted bold, is the following language:

> Standard contract terms and condition that "may not be modified" per CPUC Decision 07-11-025, and CPUC Decision 10-03-021, as modified by CPUC Decision 11-01-025, are shown in shaded text.

This language shall be deleted and replaced with the following:

> This contract has been approved by the Commission in D.[insert today's decision number]. Modification of the terms and conditions of this contract will result in the need to obtain additional Commission approval of the contract. The contract approved by D.[insert today's decision number] includes terms and conditions that "may not be modified" pursuant to prior Commission decisions, including Decision 07-11-025, Decision 08-08-028 and Decision 10-03-021, as modified by

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[77] D.07-07-027, D.08-08-028, D.10-03-021, and D.11-01-025 at 26-32.

[78] More details on the need for Commission approval to modify STC can be found at D.04-06-014 as modified by D07-02-011 and D.07-05-057 (decisions addressing STCs in the context of the RPS program).

Decision 11-01-025, and these terms and conditions are shown in shaded text.

Moreover, regarding the "non-modifiable" terms and conditions, the IOUs are directed to identify them by highlighting these terms throughout the document and include an explanation.

5.4. Clean Coalition's Proposed Standard Contract is Rejected

On August 15, 2012, Clean Coalition filed a contract in this proceeding, referred to as a "model contract" to be used in lieu of the draft joint standard contract developed by the IOUs at the direction of the assigned Commissioner and ALJ. We deny Clean Coalition's request.

By ruling dated January 10, 2012, the assigned Commissioner and ALJ in this proceeding directed the IOUs to file a standard contract. During the proceeding, parties had several opportunities to comment on this contract.[79] The Commission also directed the parties to meet and confer on several different occasions to resolve disputes regarding the proposed terms and conditions. The Agricultural Energy Consumers Association (AECA) and Sierra Club state support for the alternative contract on the basis that it is workable but does not elaborate further.[80] Several parties state their opposition to Clean Coalition's contract.

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[79] *Joint Assigned Commissioner's and Administrative Law Judge's Ruling Setting Workshop on a Utility Standard Form Contract for Section 399.20 Feed-In Tariff Program,* issued January 10, 2012, R.11-05-005.

[80] AECA September 10, 2012 comments at 4. Sierra Club September 11, 2012 comments at 7.

Clean Coalition submitted this contract late in the consideration of this issue and in a manner that can be viewed as inconsistent with the process established by the assigned Commissioner and ALJ. Specifically, the model contract was not vetted by all parties; rather we received only a few reply comments on it. While Clean Coalition claims that its proposal will further streamline the contracting process, we find that the contract we adopt today, which has been vetted by parties over approximately 12 months, strikes the appropriate balance between necessary detail and brevity by including all the information needed to protect parties with substantial investments from potential risks. That said, we considered Clean Coalition's comments regarding the needs of small developers and address them in our discussion of specific sections of the standard contract, in Section 6 herein.

Clean Coalition's request is denied.

5.5. No Need for Separate Contract for Smaller Projects (under 1 MW)

CALSEIA states that a second simplified standard contract is needed to facilitate smaller projects (under 1 MW).[81] CALSEIA suggests that a 500 Kilowatt (kW) project is unable to meet the same insurance, telemetry, forecasting, meteorological and collateral requirements as a 3 MW project. For now, we will not consider creating another standard contract. We have adopted a process, which includes the joint standard contract for the FiT program, that is efficient and streamlined. Creating an additional contract at this point will unnecessarily

[81] CALSEIA August 15, 2012 comments at 4.

complicate the administration of the program and provide limited, if any, additional cost savings for developers.

CALSEIA's request is denied.

5.6. Separate Provision for Bioenergy Addressed with SB 1122

AECA suggests that the draft joint standard contract be modified to reflect specific characteristics of bioenergy projects where the biogas capture and energy generation are separate activities at energy generation sites. AECA also claims that the provision in the contract prohibiting additional "state incentives" could preclude grants for improved methane capture and destruction. Regarding AECA's point about the specific characteristics of bioenergy projects being reflected in the joint standard contract, we will be addressing many issues specific to bioenergy when we implement SB 1122 and will consider AECA's issue in that context.

6. Discussion of Specific Sections of the FiT Joint Standard Contract

The discussion below identifies and resolves each disputed provision in the draft joint standard contract and is organized by the separate Sections of the draft contract.

Section 2 – Definition of Product

Placer County Air Pollution Control District (Placer District) states that the definition of "Product" should be clarified to exclude non-electric energy produced by the facility, such as biochar and heat.[82]

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[82] Placer District August 15, 2012 comments at 7.

We find that the definition of Product set forth in the draft contract is sufficiently clear and no need exists for modification at this time. Nevertheless, Placer District's concerns reflect the potential need to further refine the joint standard contract to more specifically address the needs of projects that fall within the parameters of SB 1122.

We will be addressing many issues specific to bioenergy when we implement SB 1122 and will consider Placer District's issue in that context.

Sections 2.8 and 2.9 - Commercial Operation Date and Extension

Some parties request a longer time period before the COD[83] (24 months) is triggered and a longer time period under the Notice of Permitted Extension[84] (six months).[85] Other parties suggest a shorter time period for both the COD and Notice of Permitted Extension.

In comments dated April 8, 2013, Clean Coalition clarifies that it requests a shorter COD but unlimited extensions for delays outside of the control of the developer.[86] Clean Coalition suggests that interconnection delays are an example of a delay outside of the control of the developer.[87] However, no evidence exists in the record that all interconnection delays are outside the control of the developer. Importantly, projects must complete a study showing the ability to interconnect with the distribution system to be eligible for a FiT contract. Allowing unlimited extensions to the COD could also result in program capacity being occupied, potentially for many years, by non-viable projects

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[83] The Commercial Operation Date is found in Section 2.8 of the draft joint standard contract.

[84] Notice of Permitted Extension is found in Section 2.9 of the draft joint standard contract.

[85] Clean Coalition August 15, 2012 comments at 5; Placer District August 15, 2012 comments at 2-3; SEIA August 15, 2012 comments at 11, Henwood Associates, Inc. (Henwood) August 15, 2012 comments at 7-8.

[86] Clean Coalition April 8, 2013 comments at 21-22.

[87] Clean Coalition April 8, 2013 comments at 21-22.

crowding out more viable projects. Clean Coalition's suggestion for unlimited extensions also introduces further delays by requiring a determination of which party to the contract is responsible for the delay before a further extension will be granted. For these reasons, Clean Coalition's suggestion is not adopted.

In D.12-05-035, the Commission provided for a 24 month period for the COD plus a permitted extension of six months (via a Notice of Permitted Extension).[88] We considered this matter in D.12-05-035. No new information has been provided by parties to persuade us to change our determination.

As a result, we decline to modify the previously adopted 24 month period before the COD plus a permitted extension of 6 months (via a Notice of Permitted Extension). Accordingly, we adopt the term in the July 18, 2012 draft joint standard contract.

SEIA and Placer District raise the issue that the proposed contract would require the seller to provide 60 days' notice to the buyer before the COD.[89] Placer District states that developers of small-scale forest biopower represent relatively new technology in rural areas and lack experience in permitting and, as a result, the 60 days' notice is a difficult time-line to meet.[90] The IOUs state that 60 days is required to provide for coordinating the scheduling of the power and other administrative functions.[91]

We find that it is reasonable to request that the seller provide 60 days' notice to the buyer before COD so that the buyer can make necessary arrangements for the scheduling of power and other administrative functions.

Accordingly, we adopt the term in the July 18, 2012 draft joint standard contract.

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[88] D.12-05-035 at 70.

[89] Draft joint standard contract at Section 2.8.1.

[90] Placer District August 15, 2012 comments at 2.

[91] IOUs September 10, 2012 joint comments at 10.

Section 2.8.2.4 - Related Damages for Failure to Meet Guaranteed Commercial Operation Date

Placer District states that the damages provision associated with failure to meet the Guaranteed Commercial Operation Date, as set forth in Section 2.8.2.4, is problematic because the damages provision prevents financing of small projects. Placer District recommends that this provision be replaced with a fixed amount or capped amount based on the value of contract.[92] Placer District presents no evidence that this damages provision hinders financing.

We find that the provision appropriately balances the need to protect ratepayers from project failure by including actual damages when the party fails to perform and our effort to streamline project financing by clearly stating the potential costs associated with the contract.

Accordingly, we adopt the term in the July 18, 2012 draft joint standard contract.

Section 3.2 - Contract Quantity over Term of Contract

Placer District states that the seller should be permitted to update the Contract Quantity one time each year during the term of the contract.[93] Contract terms include 10, 15 and 20 years. Clean Coalition states that Section 3.2 (Contract Quantity) should be entirely stricken to, presumably, permit changes to Contract Quantity upon request.[94] The IOUs state that this contract term permits the seller to modify the Contract Quantity once after the Contract Capacity has been confirmed and deliveries have begun and that changing the Contract Quantity more often makes it difficult for the IOUs to plan the amount of RPS-eligible energy needed in advance to meet the 33% RPS requirement.[95] The City of San Diego contends that in an excess sales situation, it is unreasonable to require the Seller to predict Contract Quantity because the site load is often unpredictable.[96]

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[92] Placer District August 15, 2012 comments at 2.

[93] Placer District August 15, 2012 comments at 4.

[94] Clean Coalition August 15, 2012 comments at 6.

[95] IOUs September 10, 2012 joint comments at 10.

[96] City of San Diego April 8, 2013 comments at 3-5.

We find predictability in Contract Quantity to be a fundamental element of the standard contract and that the proposed provision, only permitting a one-time change, is a reasonable means of providing the buyer and seller with the ability to plan accordingly. Regarding the concerns raised by the City of San Diego, we will monitor the impact of the contract provision in the context of excess sales.

Accordingly, we adopt the term in the July 18, 2012 draft joint standard contract.

Section 3.5 - Contract Term

Clean Coalition requests that the Commission add a 25-year contract term option for the FiT program.[97] The IOUs state that Clean Coalition's proposed 25-year contract term is inconsistent with the explicit language of § 399.20(d)(1), which states that "[t]he tariff shall provide for payment for every kilowatthour of electricity purchased from an electric generating facility for a period of 10, 15, or 20 years, as authorized by the Commission."[98]

Consistent with § 399.20(d)(1), the draft joint standard contract correctly gives the seller the option of a 10, 15, or 20-year contract term. To require the IOUs to provide a 25-year contract term would conflict with the language of § 399.20. The request is denied.

Accordingly, we adopt the provision in the July 18, 2012 draft joint standard contract.

Section 3.5.4 – Commercial Operation Date and Collateral Requirement

Clean Coalition states that Section 3.5.4 should be stricken since no Collateral Requirement should apply after the Commercial Operation Date.[99] Clean Coalition provides no rationale to support its recommendation.

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[97] Clean Coalition August 15, 2012 comments at 6; Henwood August 15, 2012 comments at 6.

[98] IOUs September 10, 2012 joint comments at 11.

[99] Clean Coalition August 15, 2012 comments at 6.

TURN notes that non-performance is one concern but that collateral also protects ratepayers from a seller intentionally breaching a contract if opportunities arise to sell to another party at a higher price.[100]

We find it reasonable to maintain the Collateral Requirements after the Commercial Operation Date since ratepayers continue to be at risk until the full contract term expires and performance has been delivered according to the terms of the contract.

Accordingly, we adopt the provision in the July 18, 2012 draft joint standard contract.

Section 3.7 - Billing and Payment Terms

Clean Coalition objects to the contract provision requiring sellers to provide buyers with a billing invoice on the basis that billing is administratively burdensome and costly for small developers.[101] The IOUs respond that monthly billing is a requirement in other programs and that no evidence exists that monthly billing imposes an undue burden on sellers.[102] The IOUs further state that monthly billing is standard practice for business transactions and that it benefits both sellers and buyers by helping to mitigate billing disputes early.[103]

While developers may gain slight administrative efficiencies from a longer billing period, we find that greater benefits will be achieved over the term of these contracts with the more frequent monthly billing, which is the standard practice. Monthly billing will provide the contracting parties with more frequent opportunities to communicate on payment, which is a critical aspect of the contracting relationship.

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[100] TURN April 15, 2013 comments at 5.

[101] Clean Coalition August 15, 2012 comments at 6.

[102] IOUs September 10, 2012 joint comments at 11-12.

[103] IOUs September 10, 2012 joint comments at 11-12.

Accordingly, we adopt the provision in the July 18, 2012 draft joint standard contract.

Section 4.1 - Green Attributes

Placer District states that the "non-modifiable" standard term and condition in the draft joint standard contract "Green Attributes" is outdated.[104]

As noted in the October 5, 2012 Assigned Commissioner's Ruling,[105] review of this "non-modifiable" standard term and condition will take place during our overall review of the RPS procurement process in this proceeding.[106] We anticipate that we will address and, perhaps, revise this term at that time. At that time, we will direct the utilities to conform the FiT program as needed. Accordingly, we adopt the provision in the July 18, 2012 draft joint standard contract.

Section 4.3 - WREGIS

Clean Coalition and Henwood state that PG&E and SDG&E should conform to SCE's proposal in the draft joint standard contract and act as the Qualified Reporting Entities (QREs) for the Western Renewable Energy Generation Information System[107] (WREGIS) purposes for all of their FiT projects.[108] At Section 4.3 of the draft joint standard contract, PG&E and SDG&E present one proposal and SCE presents a different proposal.

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[104] Placer District August 15, 2012 at 8.

[105] *Second Assigned Commissioner's Ruling Issuing Procurement Reform Proposals and Establishing a Schedule for Comments on Proposals,* dated October 5, 2012, in R.11-05-005 (October 5, 2012 ACR).

[106] October 5, 2012 ACR at 38.

[107] WREGIS is an independent, renewable energy tracking system for the region covered by the Western Electricity Coordinating Council. WREGIS tracks renewable energy generation from units that register in the system by using verifiable data and creating renewable energy certificates (REC) for this generation.

[108] Clean Coalition August 15, 2012 comments at 6-7; Henwood August 15, 2012 comments at 8.

In response to Clean Coalition and Henwood, PG&E and SDG&E state that they do not act as QREs for any of the renewable resources they have under contract and that requiring them to do so only for FiT projects would be administratively burdensome and inefficient given their existing systems. They further state that such a requirement could lead to errors because in some cases they would be acting as the QRE with FiT but not in other cases.[109]

Henwood and Clean Coalition do not claim that developers will gain significant benefits from this change. Therefore, given the administrative challenges in creating an exception for FiT projects from PG&E's and SDG&E's standard administrative practices, Henwood's and Clean Coalition's proposal is not adopted. SCE may retain a different contract term for Section 4.3 than PG&E and SDG&E.

PG&E and SDG&E submitted a clarification to this standard contract provision in a September 12, 2012 email sent to the service list. This email is incorporated into the record of the proceeding and content of this email is reflected here.[110] In addition, this clarification, which pertains to QRE function for projects under 1 MW, should be reflected in the joint standard contract.

Accordingly, we adopt the provisions in the July 18, 2012 draft joint standard contract.

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[109] IOUs September 10, 2012 joint comments at 12.

[110] After filing comments on September 10, 2012, PG&E and SDG&E learned of an error pertaining to WREGIS and the utilities acting as QRE. To correct this error, PG&E and SDG&E sent an email to the service list on September 12, 2012. This email clarified that although they generally do not serve as the QRE or Account Holder for the seller's facilities in WREGIS, under PG&E's and SDG&E's AB 1969 FIT Program exceptions are made for facilities under 1 MW without a CAISO meter. In these circumstances, PG&E and SDG&E have offered to serve as the QRE for the Seller. Across all PG&E and SDG&E renewable procurement program, all facilities with a CAISO meter obtain a QRE agreement with the CAISO. PG&E and SDG&E do not serve as WREGIS Asset Managers for facilities participating in renewable procurement programs, including the FIT program.

Section 4.4.3 - Resource Adequacy Requirements

Section 4.4.3 provides that "Seller shall cooperate in good faith with Buyer to pursue and obtain any and all Capacity Attributes…." SEIA claims that Section 4.4.3 is inconsistent with D.12-05-035 and should be removed from the draft joint standard contract because it requires sellers (as opposed to providing sellers with the option) to pursue resource adequacy in certain circumstances.[111] Clean Coalition states that the term is overbroad and should be stricken.[112]

The IOUs explain that the contract does not require sellers to undertake any upgrades to obtain Full Capacity Deliverability Status but only requires sellers to perform administrative tasks such as submitting documents to be deemed eligible for RA credit *if* the Commission at a future date adopts a decision, or takes other official action, to find certain energy automatically qualifies as Fully Deliverable.[113] The IOUs further state that they are willing to modify the provision to establish a $1,000 cap on seller's total out-of-pocket costs under this provision and that buyer will reimburse seller for any additional expenses.[114]

Pursuant to § 399.20(i), sellers must be provided with the option to change RA status. [115] In accordance with D.12-05-035, sellers are not required to pursue resource adequacy but sellers have the option of converting to Full Capacity Deliverability Status at any time during the term of the Contract.[116] However, sellers should not refuse to take action required to participate in unburdensome requests that would enable the IOUs and CAISO to assign resource adequacy value to the generation. Furthermore, *if* the Commission at some future date adopts a rule that "deems the energy subject to a FiT contract eligible for RA status," as suggested by the IOUs, we will revise the contracts to reflect this

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[111] SEIA August 15, 2012 comments at 11-12.

[112] Clean Coalition August 15, 2012 comments at 7.

[113] IOUs September 10, 2012 joint comments at 13-15.

[114] AECA September 9, 2012 comments at 3; CALSEIA August 29, 2012 comments at 3.

[115] D.12-05-035 at 54-56.

[116] D.12-05-035 at 54-56.

change in law, as needed. Sellers are obliged to abide by the rules of the Commission on resource adequacy and the rules of other jurisdictions, such as the CAISO. The Commission does not limit the ability of the IOUs to require a FiT generator to comply with the rules of other jurisdictions on this matter.

Accordingly, the IOUs are directed to revise the draft joint standard contract to clarify that sellers are provided the option to convert, at their discretion, to Full Capacity Deliverability Status in accordance with § 399.20(i) and D.12-05-035.

Section 4.6 - Compliance Expenditure Cap

SEIA and Clean Coalition state that the yearly Compliance Expenditure Cap of $25,000 for costs related to changes in California Energy Commission (CEC) Pre-Certification, CEC Certification or CEC Verification regulations during the term of the contract and pertaining to ensuring the energy is from an eligible renewable energy resource is too high and should be determined on a case-by-case basis based on the size of the project or limited to $5,000 annually.[117]

The IOUs state that the $25,000 cap (for each year for the term of contract) reflects efforts to share exposure to increased costs resulting from changes in law or regulation between buyer and seller and is appropriate based on the size of the FiT projects.[118] The IOUs further state that the cap applicable to larger RPS projects is typically higher and that a cap of $25,000 is a small percentage of total potential revenues.[119]

We find the yearly cap of $25,000 is a reasonable means of sharing the risk of additional costs that would be potentially incurred with changes in the law. We

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[117] SEIA August 15, 2012 comments at 14; Clean Coalition August 15, 2012 comments at 7. In Clean Coalition's September 10, 2012 comments at 21, Clean Coalition requests that this cap be limited to $5000 annually and suggests that the compliance expenditure cap extends to interconnection fees, legal fees and other costs. Clean Coalition is incorrect. This cap applies to fees only as described above.

[118] IOUs September 10, 2012 joint comments at 15.

[119] IOUs September 10, 2012 joint comments at 15.

acknowledge that the primary obligation to pay costs will be placed on the seller but that such an outcome is consistent with the seller's obligation to ensure that its facility is operating consistent with the regulations of the CEC pertaining to renewable facilities. Under this term, amounts exceeding $25,000 will be paid by either the seller or the buyer in amounts to be determined by the parties.

Accordingly, we adopt the provision in the July 18, 2012 draft joint standard contract.

Section 4.7 - Eligible Intermittent Resources Protocol Requirements

Clean Coalition states that Eligible Intermittent Resources Protocol (EIRP) Requirements described in Section 4.7 should only apply to facilities over 1 MW.[120] Section 4.7 provides, in part, that "If at any time during the Term the Facility is eligible for EIRP, Seller shall provide Buyer with a copy of the notice from CAISO certifying the Facility as a Participating Intermittent Resource as soon as practicable …." No rationale is given to support this request.

The IOUs do not address this issue in their September 10, 2012 comments.

We adopt the term in the July 18, 2012 draft joint standard contract but will monitor this matter for potential disputes and consider revising this term as needed in the future should additional information arise to further inform the issue.

Sections 4.8 and 5.3.6 - Qualifying Facility Status

Placer District states that the FERC requirements exempt participating generators less than 1 MW from filing the FERC Qualifying Facility Registration Form 556 and, therefore, the Commission should exempt those FiT projects sized less than 1 MW from complying with the Form 556 requirements.[121] The IOUs state that Placer District misinterprets the Form 556 requirements and that generators under 1 MW are not automatically Qualifying Facilities (QFs).[122]

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[120] Clean Coalition August 15, 2012 comments at 7.

[121] Placer District August 15, 2012 comments at 7.

[122] IOUs September 10, 2012 joint comments at 15.

In response, we clarify that the program offered under the draft joint standard contract is only available to sellers that are QFs. We encourage sellers to formally obtain this status through FERC to reduce the uncertainties in the contracting process but we will not order the filing of a form when not required by FERC. In short, the seller must be a QF to participate in the FiT program. It is the responsibility of the sellers to complete all necessary documents with FERC. If FERC does not require any action be taken to be a QF, we will not require any.

Accordingly, we adopt the terms set forth in the July 18, 2012 draft joint standard contract but modified to indicate that if no action before FERC is required to confirm a seller's status as a QF, the IOUs will likewise not require any. This finding represents a modification to D.12-05-035.[123]

Section 5.3.2 - Seller's Representations, Warranties, and Covenants

Section 5.3.2 states that "Seller's execution of this Agreement will not violate Public Utilities Code Section 2821(d)(1), if applicable." Clean Coalition states that this term should be clarified so that it only applies to hydro projects.[124] Clean Coalition provides no rationale to support its request. The IOUs do not address this issue. We find that no clarification is needed as the code section speaks for itself. Accordingly, we adopt the provision in the July 18, 2012 draft joint standard contract.

Section 5.3.8 - Seller's Representations, Warranties, and Covenants

Clean Coalition states that Section 5.3.8 should be moved to the general representations, warranties and covenants section of the joint standard contract so that it applies to buyers and sellers, rather than to just sellers.[125] Section 5.3.8 states that the seller "is acting for its own account, has made its own independent decision to enter into this Agreement…." Clean Coalition provides no rationale to support its request. The IOUs do not address this issue in their September 10, 2012 comments.

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[123] D.12-05-035 at 102.

[124] Clean Coalition August 15, 2012 comments at 7.

[125] Clean Coalition August 15, 2012 comments at 7.

We do not accept Clean Coalition's suggestion to move Section 5.3.8 to general representations, warranties, covenants Section so that it applies to the buyer and seller as it provides protections to the seller, as potentially the less sophisticated party, not needed for the buyer.

Accordingly, we adopt the term in the July 18, 2012 draft joint standard contract.

Section 5.3.9 - Other Product Transactions

Placer District states its intent to sell power to buyers not covered by the FiT program. It requests approval to engage in such transactions and suggests that Section 5.3.9 prohibits these arrangements.[126]

The language in the draft joint standard contract does not appear to prohibit or even address such sales but, instead, the relevant language appears to prohibit a seller from entering into a sale (and other types of transactions) of the Product subject to the contract. The July 18, 2012 draft joint standard contract provides as follows:

> Section 5.3.9. As of the Execution Date and throughout the Term: (a) Seller will not convey, transfer, allocate, designate, award, report or otherwise provide any or all of the Product, or any portion thereof, or any benefits derived there from, to any party other than Buyer; and (b) Seller will not start-up or operate the Facility per instruction of or for the benefit of any third party, except as required by other Laws or, in the case of excess sale arrangements, to serve any Site Host Load;[127]

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[126] Placer District August 15, 2012 comments at 3-4.

[127] In April 15, 2013 comments to the proposed decision on this matter, Placer District suggests that this provision could be further clarified by replacing the phrase "except as required by other Laws" with "except as allowed by other Laws."[127] We agree. SCE suggests that additional language be added to further clarify that the joint standard contract is already net of "site host load" for excess sales arrangement, specifically, add the following phrase "or, in the case of excess sale arrangements, to serve any Site Host Load." We agree.

With these clarifications, we find that the above provision does not prohibit the type of additional sales transactions described by Placer District.

Accordingly, we adopt the term in the July 18, 2012 draft joint standard contract.

Sections 5.3.12 and 5.3.13 - Interconnection

Clean Coalition states that Sections 5.3.12 and 5.3.13, which concern interconnection issues, are over-reaching and should be removed as beyond the scope of a power purchase agreement.[128] These Sections provide as follows:

> Section 5.3.12 No other person or entity, including any other generating facility has any rights in connection with Sellers' interconnection agreement or Seller's Interconnection Facilities and no other persons or entities shall have any such rights during the Term; and
>
> Section 5.3.13 During the Term, Seller shall not allow any other person or entity, including any other generating facility, to use Seller's Interconnection Facilities.

Clean Coalition provides no rationale to support its request. The IOUs do not address this issue in comments.

We find these terms promote administrative ease by providing a reasonable means of ensuring that FiT contracts proceed in an expeditious and non-controversial fashion.

Accordingly, we adopt the term in the July 18, 2012 draft joint standard contract.

Section 6.5.1 - Administrative Logs

Placer District states that the requirement that sellers maintain a daily log of material operations and maintenance information, to provide to the buyer within twenty days of the buyer's request, is too onerous, particularly when no changes

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[128] Clean Coalition August 15, 2012 comments at 8.

or actions occur.[129] Placer District provides specific suggestions to modify the contract language. The IOUs state that because the provision is limited to "material" information, it is not overly burdensome.[130]

We are not convinced that the concerns noted by Placer District outweigh the benefits – especially safety related - derived from maintaining a daily log of material operations and maintenance information.

Accordingly, we adopt the term in the July 18, 2012 draft joint standard contract.

Section 6.12 - Reporting and Record Retention

Clean Coalition states the requirement for reporting and record retention as overly burdensome and a financial hardship.[131] Section 6.12.1 of the draft joint standard contract provides "Seller shall provide Project development status reports in a format and a frequency, which shall not exceed one (1) report per month, specified by the Buyer." Specifically, Clean Coalition states that Section 6.12.1 should require less frequent reports, and Section 6.12.4 should require Commission approval instead of simply buyer's "sole discretion."[132] Clean Coalition provides no further rationale to support its request. In comments on the proposed decision and alternate proposed decision, Clean Coalition emphasizes that the reporting requirement is a time burden.[133]

The IOUs state that preparing a monthly status report allows the buyer and seller to coordinate on the administration of the contract so that both parties can respond to any changes to the project in a timely manner, that monthly progress reporting is a standard practice for many renewable projects, and that an IOU

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[129] Placer District August 15. 2012 comments at 6.

[130] IOUs September 10, 2012 joint comments at 16.

[131] Clean Coalition August 15, 2012 comments at 8.

[132] Clean Coalition August 15, 2012 comments at 8.

[133] Clean Coalition April 8, 2013 comments at 9.

may request a report less than once per month (e.g., quarterly, semi-annually, or annually), which means there may be even less of a burden on sellers.[134]

We find that the term in the draft joint standard contract provides a reasonable balance between ensuring the timely exchange of information between the contracting parties to support efficient and safe transactions and streamlining the contracting process to meet the specific needs of FiT developers.

Accordingly, we adopt the term in the July 18, 2012 draft joint standard contract.

Section 6.12.3 - Women, Minority and Disabled Veteran-owned Business Enterprises (WMDVBE)

Placer District states that the requirement in the contract to provide a list of all WMDVBE that supplied goods and services is overly burdensome unless the IOUs pay for this effort.[135] It also claims that this acronym is not defined and no legal requirement is cited.[136]

The definition is included at Appendix A of the draft contract. We further direct the IOUs to define the acronym, which reflects "Women, Minority and Disabled Veteran-owned Business Enterprises." Moreover, we do not find this contract term to be overly burdensome but, instead, it achieves a reasonable balance between the buyer's need for information to ensure compliance with laws related to WMDVBE and the seller's need to assist with the compliance of such laws. We do not accept the proposal for the IOUs to pay for any work related to the IOUs' requests to sellers related to WMDVBE.

Accordingly, we adopt the terms in the July 18, 2012 draft joint standard contract.

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[134] IOUs September 10, 2012 joint comments at 17.

[135] Placer District August 15, 2012 comments at 6-7.

[136] Placer District August 15, 2012 comments at 6-7.

Section 6.14 - Modification to Facility

Placer District objects to the requirement that the seller obtain the buyer's consent to a modification to the generating facility on the basis that the facility modifications are outside of the buyer's purview and that requiring buyer's consent creates a disincentive for modifications that could boost productivity.[137] Clean Coalition generally agrees.[138] The IOUs state that, as a party to the FiT contract, an IOU has a vested interest in a facility producing the product it is buying and that if, for example, an IOU enters into a contract for a 1.5 MW project, but the seller transforms that project it into a 3 MW project, the 3 MW project is no longer the same project from which the IOU agreed to purchase energy under the contract.[139] SCE clarifies that oversight of facility modifications is important but that the intention is not to prevent every possible modification to a generating facility, no matter how small.[140] Instead, SCE proposes to limit the IOUs' right to consent based on the materiality of the change.

We find that requiring the seller to obtain the buyer's consent before making any modifications to its facility imposes an unreasonably vague burden on the seller. The benefits, if any, of such a requirement are outweighed by the goal of streamlining the contracting process for projects under the FiT program. However, we find that a requirement that the seller obtain the buyer's consent to material modifications of the generating facility is reasonable as this requirement promotes cost containment by restricting modifications to facilities that change the capacity of the project or type of technology used for generation.[141]

Accordingly, we do not adopt this term in the July 18, 2012 draft joint standard contract. Instead, we direct the IOUs to incorporate a materiality standard into

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[137] Placer District August 15, 2012 comments at 4.

[138] Clean Coalition August 15, 2012 comments at 8.

[139] IOUs September 10, 2012 joint comments at 17.

[140] SCE April, 2013 comments at 13.

[141] The language provided in SCE's April 8, 2013 comments at 14 is acceptable for reflecting the materiality standard.

this provision. We also acknowledge that other laws and requirements may apply in such a situation to require the seller to inform the buyer of a modification to a facility.

Section 10 - Insurance Requirements

Clean Coalition, SEIA, and Henwood object to the insurance provisions in the draft joint standard contract. They assert that no insurance beyond general liability should be required, that the level of insurance required is too high, and that insurance should not have to be in place at the time of contract signing.[142] CALSEIA and AECA agree.[143]

In response, the IOUs state that the insurance requirements protect ratepayers from potentially significant liability and reflect commercially reasonable risk management practices for both the buyers and sellers that are ubiquitous in similar commercial transactions. The insurance provision proposed in the draft joint standard contract is similar to the insurance provisions from SCE's Solar Photovoltaic Program (SPVP) PPA for generators less than 5 MW. The IOUs state that generators have executed SCE's SPVP PPA, secured financing and achieved commercial operation under that PPA. In short, the IOUs state that no evidence exists that the proposed insurance provision will hinder project development or financing. The IOUs further state that, because the IOUs are exposed to liability risk beginning upon execution of the PPA (e.g., such as risks arising from development and construction activities), sellers should be required to provide insurance concurrently with the execution of the standard contract. Finally, the IOUs note that, in their experience, smaller projects do not have commensurately smaller risks, as the costs associated with a death or injury are not different just because a project is smaller and that the proposed insurance requirements are consistent with the IOUs' market risk exposure and industry standards.[144]

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[142] Clean Coalition August 15, 2012 comments at 8; SEIA comments at 14-15; Henwood August 15, 2012 comments at 9.

[143] CALSEIA reply comments August 29, 2012 at 3; AECA reply comments September 9, 2012 at 2.

[144] IOUs September 10, 2012 joint comments at 18-19.

We find that the risks to ratepayers throughout the contracting term are sufficiently high to justify the requirements imposed upon sellers by the draft joint standard contract term. We are committed to streamlining and reducing the overall costs related to the FiT contracting process but find this area sufficiently important to justify the imposition of the proposed insurance provision. To ease the administration burden on sellers, we require the IOUs to provide that sellers must offer evidence of insurance 60 days after contract execution or before construction begins.[145]

Accordingly, we adopt the term in the July 18, 2012 draft joint standard contract.

Section 11 - Force Majeure

AECA states that the 1-year period for Force Majeure that triggers contract termination options does not appropriately take into consideration Force Majeure events at dairy and other biogas projects, such as a catastrophic animal disease, which merit additional discretion and flexibility.[146] The IOUs provide no response. This issue was raised in reply comments and, as such, other parties may not have been aware of the issue and the record remains undeveloped with the exception of AECA's stated concern. In addition, we will be addressing many issues specific to bioenergy when we implement SB 1122. AECA's concerns should be raised in that context.

Section 12 - Guaranteed Energy Production

Clean Coalition and Placer District state that the Guaranteed Energy Production provision in the draft joint standard contract should be stricken or, at the very least, that the buyer must justify the required production quantity with empirical data.[147] These parties state that this provision hinders financing.[148]

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[145] TURN April 15, 2013 comments at

[146] AECA September 9, 2012 comments at 3-4.

[147] Clean Coalition August 15, 2012 comments at 9; Placer District at 5.

[148] Clean Coalition August 15, 2012 comments at 9; Placer District at 5.

The IOUs state that sellers must already specify the expected energy production from the generator in the draft joint standard contract and, as a result, meeting the Guaranteed Energy Production should not be problematic.[149] In addition, the provision provides a cushion that allows for a reasonable amount of over- or under-generation.[150]

We find that the proposed term reasonably balances the buyer's need to have a high level of certainty regarding the expected generation and the seller's need for flexibility to account for unknowns by permitting a specific amount of over- or under-generation. We do not, however, agree with the IOUs that Section 12 serves to implement § 399.20(j)(1).[151]

Accordingly, we adopt the term in the July 18, 2012 draft joint standard contract.

Section 13 - Collateral Requirements

Clean Coalition and Henwood state that the IOUs' proposed development security requirements ($50/kW for projects over 1 MW, and $20/kW for projects under 1 MW) are too high and state that the collateral requirements should only apply until the project's Commercial Operation Date.[152]

The IOUs respond that the increased amounts in the draft joint standard contract assist in distinguishing viable projects from non-viable projects.[153] The IOUs

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[149] IOUs September 10, 2012 joint comments 19-20.

[150] IOUs September 10, 2012 joint comments 19-20.

[151] § 399.20(j)(1) provides that "The commission shall establish performance standards for any electric generation facility that has a capacity greater than one megawatt to ensure that those facilities are constructed, operated, and maintained to generate the expected annual net production of electricity and do not impact system reliability."

[152] Clean Coalition August 15, 2012 comments at 9; Henwood August 15, 2012 comments at 9-10.

[153] IOUs September 10, 2012 joint comments at 20-21. The IOUs propose $20/kW for under 1 MW projects and $50/kW for over 1 MW projects.

further state that other renewable projects with similar credit and collateral requirements have secured financing and have begun commercial operations, which demonstrates that the proposed credit and collateral provisions are not an unreasonable burden on generators.[154] In response to the claim that collateral requirements should only apply until the project's Commercial Operation Date, the IOUs state that collateral is required after the Commercial Operation Date because it keeps the IOUs' customers whole if the seller fails to perform consistent with its contractual obligations.[155] The IOUs point out that, in the event of the seller's non-compliance with the energy output requirements, the buyer will not necessarily have the option to buy replacement energy on the market at a lower price.[156]

In the context of FiT, we most recently addressed the issue of collateral used for development security in D.11-11-012.[157] In. D.11-11-012, we modified SCE's then-existing CREST contract (SCE's FiT contract under AB 1969). We found then that $20/kW for collateral used for development security in that contract was a reasonable balance between discouraging non-viable projects from participating in the program, while protecting ratepayers in the event projects fail, with providing smaller developers with streamlined access to the program.[158] Our position on this topic remains unchanged. We also recognize the need for collateral through the term of the contract.

Accordingly, we adopt an amount lower than the IOUs proposed in the July 18, 2012 draft joint standard contract for project development security. The amount we adopt is $20/kW for all eligible FiT projects and we allow the IOUs

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[154] IOUs September 10, 2012 joint comments at 20-21.

[155] IOUs September 10, 2012 joint comments at 20-21.

[156] IOUs September 10, 2012 joint comments at 20-21.

[157] D.11-11-012, *Decision Granting, with Modifications, the Motion by Clean Coalition for Immediate Amendments of the Southern California Edison Company AB 1969 CREST Power Purchase Agreement* (issued November 17, 2011), R.11-05-005.

[158] D.11-11-012 at 33-34.

to maintain the collateral requirement through the term of the contract. The IOUs shall modify the joint standard contract accordingly.

Section 13.5.3 - Payment of Interest on Collateral

Mr. L. Jan Reid (Reid) states that Section 13.5.3 incorrectly cites Section 3.7.9 as setting forth the applicable interest rate when that rate is, instead, found in Appendix A.[159] In comments to the proposed decision, SCE clarified that the citation is correct but perhaps should be clarified.[160] We agree that additional clarification of Section 13.5.3 would be helpful. Accordingly, to correct this citation error, the IOUs shall change Section 13.5.3 of the July 18, 2012 draft joint standard contract to read "Payment of Interest. Buyer shall pay simple interest on cash held to satisfy the Collateral Requirements at the rate and in the manner set forth in Section 3.7.9."

Section 13.6 - Letter of Credit Requirements

Henwood requests that the Commission provide greater latitude in the selection of banks that are permitted to issue letters of credit for FiT financing than provided for under the draft joint standard contract.[161] The IOUs state that, since the draft joint standard contract was first circulated, the credit rating requirement has been reduced to allow a Moody's A3 rating or an S&P A-rating with a stable outlook, but that further reducing the requirement may put ratepayers at risk.[162] The IOUs further state that using a letter of credit is a standard commercial practice that is appropriate to protect customers and ensure that they receive any funds or amounts owed under the FiT standard contract.[163]

Under the terms of the draft joint standard contract, the letter of credit requirements would be consistent across the large-scale RPS program, the RAM program and FiT. We reduce the letter of credit requirements as noted by the

[159] Reid August 15, 2012 comments at 6.

[160] SCE April 8, 2013 comments at 15.

[161] Henwood August 15, 2012 comments at 10.

[162] IOUs September 10, 2012 joint comments at 22.

[163] IOUs September 10, 2012 joint comments at 22.

IOUs but no further. We find that, by requiring the above credit rating for banks issuing letters of credit to developers, we are reasonably balancing the need to protect ratepayers from risk of loss with the need to provide developers with increased access to more banks in order to secure financing.

Accordingly, we adopt the letter of credit requirements in the July 18, 2012 draft joint standard contract.

Section 14.9 - Transmission Costs & Termination Rights

Several parties raise questions about Section 14.9 of the draft joint standard contract, which provides, generally, that a termination right becomes effective within 60-days if the Aggregate Network Upgrade Costs exceeds $300,000 or if the buyer must procure transmission service from any other transmission/distribution owner, which is not reimbursed or paid by the seller.

Reid states that the 60-day notice provisions in the draft joint standard contract at Section 14.9.1 that provides the buyer the right to terminate the contract after the seller provides the results of certain interconnection studies is too long. Reid requests a 30-day notice period.[164] AECA states that the cap on transmission cost of $300,000 needs to be more flexible to accommodate fixed-location technologies, such as bioenergy.[165] Clean Coalition states that the cap on transmission costs is problematic for all the reasons raised in its application for rehearing[166] but does not provide any further specifics.[167]

In response to Reid, the IOUs state that 60 days is a reasonable balance between the desire for certainty by the parties regarding the terms of the transaction, verifying transmission costs, and researching options available to the parties

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[164] Reid August 15, 2012 comments at 6-7.

[165] AECA September 10, 2012 comments at 3.

[166] Clean Coalition filed a timely application for rehearing of D.12-05-035 on June 29, 2012. This application for rehearing was denied, with modification, in D.13-01-041.

[167] Clean Coalition August 15, 2012 comments at 10.

going forward.[168] We agree. The IOUs do not address the points raised by Clean Coalition and AECA.

Clean Coalition alleges that the cost cap unlawfully eliminates a substantial portion of potential FiT projects but fails to identify any law which is violated.[169] We found no legal error in D.13-01-041 when addressing this same issue when raised by Clean Coalition in its Application for Rehearing. Likewise, because Clean Coalition provides no new information now, we make no modifications to the transmission cap adopted in D.12-05-035 or the provision in the draft joint standard contract. Regarding AECA's point that the termination rights do not properly account for fixed-location generation, such as biogas, we will be addressing issues specific to bioenergy when we implement SB 1122 and AECA may raise this issue in that context.

Accordingly, we adopt the language in the July 18, 2012 draft joint standard contract.

Section 15 and Appendix D - Forecasting

Section 15 and Appendix D of the draft joint standard contract requires sellers be responsible for forecasts.

Clean Coalition states that, to achieve greater efficiencies, the buyer should be responsible for forecasts (not seller).[170] In the alternative, Clean Coalition proposes that sellers only be required to provide a single, monthly forecast of expected generation. SEIA, CALSEIA, Sierra Club, AECA suggest that sellers have the option to forecast (Appendix D of draft joint standard contract) and pay buyer a reasonable cost for this service. The IOUs do not address this issue.

We find that providing sellers with the option of paying buyer a reasonable fee for the forecasting service is reasonable. This outcome furthers our goal of

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[168] IOUs September 10, 2012 joint comments 23.

[169] D.13-01-041 at 15-16.

[170] Clean Coalition August 15, 2012 comments at 10.

streamlining the FiT contracting process by reducing the burden on the small developers without subjecting ratepayers to additional costs or risks.

Section 16.2 - Recording Phone Conversations

Clean Coalition states that Section 16.2 of the draft joint standard contract, which permits the recording of phone conversations in certain circumstances related to the scheduling of energy, should be stricken as over-reaching.[171]

The IOUs state that, in conformance with the law, they routinely record conversations between electricity schedulers and generators to retain an accurate record in case disputes later arise regarding the communication during the telephone call.[172] The IOUs explain that Section 16.2 serves to notify the sellers that phone conversations may be recorded and provides each party's consent to recording,[173] which is a standard provision in energy contracts (including renewable contracts).[174]

We find that the IOUs are operating within the law in recording conversations and, while developers may perceive this recording as an intrusion on privacy, the recording of conversations is a reasonable means of minimizing disputes and managing the public safety aspects of scheduling energy.

Accordingly, we adopt the provision in the July 18, 2012 draft joint standard contract.

Section 17 and Appendices K and L - Assignment

Clean Coalition states that, contrary to Section 17 of the draft joint standard contract, sellers should not need to obtain buyer's prior consent to assignment and, instead, only notification should be required.[175] The IOUs provide no response.

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[171] Clean Coalition August 15, 2012 comments at 10.

[172] IOUs September 10, 2012 joint comments 23.

[173] IOUs September 10, 2012 joint comments 23.

[174] IOUs September 10, 2012 joint comments 23.

[175] Clean Coalition August 15, 2012 comments at 10.

The contracts in the RPS program and the RAM program require prior consent for assignment, with certain exceptions. Because assignment transfers all the rights and responsibilities to a third-party, we find reasonable the need to obtain the consent of the buyer rather than just notifying the buyer. This provision promotes administrative ease by reasonably balancing the seller's need for flexibility to assign the contract with the buyer's need to ensure that the assignee is able to perform as required under the contract. Consent to assignment should not be unreasonably withheld.[176]

Accordingly, we adopt the provision in the July 18, 2012 draft joint standard contract.

Section 19.1 - Dispute Resolution and Recovery of Costs

Clean Coalition states that the arbitration process described in Section 19 of the draft joint standard contract should not be the sole remedy for parties and that, for example, parties should be permitted to seek court remedies.[177] Reid states that the recovery of costs by a prevailing party to a dispute should be limited to reasonable costs.[178] The IOUs state that the arbitration provision prevents forum shopping and promotes cost containment.[179]

We find that the arbitration provision reasonably balances the goal of streamlining the administration of FiT contracts with providing developers' the opportunity to successfully develop projects.

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[176] In April 15, 2013 comments, PG&E requests a modification to Section 17.2 to clarify that Appendix L represents the extent of PG&E's required consent by adding two references to "Appendix L." SCE requests a minor modification to the draft joint standard contract to enable SCE to rely on Appendix L (Financing Consent to Assignment form). We find these modifications reasonable.

[177] Clean Coalition August 15, 2012 comments at 10.

[178] Reid August 15, 2012 comments at 7.

[179] IOUs September 10, 2012 joint comments 23-24.

Accordingly, we adopt the language as proposed in the July 18, 2012 draft joint standard contract. The Commission's complaint forum is also available as noted in the July 18, 2012 draft joint standard contract

Section 20.3 - Amendments

Section 20.3 addresses additions or modifications to the joint standard contract. Reid requests that this provision be stricken.[180] In response, the IOUs explain that Section 20.3 of the draft joint standard contract protects both parties from having the agreement amended by a mere action or unsigned writings.[181] The IOUs further note that, under general contract law, regardless of the provisions in the contract, parties can always amend an agreement by a writing signed by both parties and that the Section 20.3 in the draft joint standard contract serves to limit amendments to a certain specific method (written and by both parties) and to protect against disputes that could occur under an amendment that is not in writing and executed by the parties (e.g., a verbal agreements to amend).

The contract that we approve today is a standard contract. The objectives of a standard contract are to promote administrative ease, reduce transaction costs, and protect the rights of the parties. If amendments are permitted, on even seemly minor matters, our efforts to balance these objectives may be compromised.

We recognize, however, that administrative amendments that do not impact the Commission approved standard terms and conditions of the underlying contract, for example, typos or other administrative changes, are appropriate.[182] We permit administrative amendments to joint standard contract because, otherwise overall contract administration costs will increase as well as the burden of administrating these contracts. Commission approval is not required for these types of amendments to the standard contract.

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[180] Reid August 15, 2012 comments at 7.

[181] IOUs September 10, 2012 joint comments at 24.

[182] PG&E April 8, 2013 comments at 7.

Accordingly, except in the limited circumstances as described above, we reject all language permitting amendments to this contract unless Commission approval of the contract, as modified, is obtained.

Appendix F - Telemetry

The July 18, 2012 draft joint standard contract includes a provision for telemetry for PG&E and SCE and a separate telemetry provision for SDG&E. These two provisions are found at Appendix F.

Regarding PG&E's and SCE's contract provision, Clean Coalition states that recurring telemetry costs should be capped at $100 per month.[183] Clean Coalition does not oppose the $20,000 cap on installation costs for telemetry for facilities that are 500 kW and less. CALSEIA agrees.[184] Clean Coalition offers no proposal as to what happens if the $100/month amount is exceeded. Henwood proposes a similar cost cap for the remaining facilities, 1 MW and above.[185] Henwood also claims that telemetry is not needed because real-time data is not used for projects of this size.[186]

The IOUs state that limiting recurring telemetry costs to $100 is not reasonable because these total costs are unknown during the potential duration of the contracts, up to 20 years.[187] The IOUs also state that real-time data is used in scheduling resources of 500 kW and above in the CAISO market.[188]

We find that the IOUs' proposal allowing projects under 500 kW to aggregate telemetry costs and to limit those costs with a $20,000 cap is a reasonable means of balancing the CAISO's need for visibility of these generators and providing the data needed so that these small generators can be scheduled (on an aggregate

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183 Clean Coalition August 15, 2012 comments at 11.

184 CALSEIA August 29, 2012 comments at 3.

185 Henwood August 15, 2012 comments at 7.

186 Henwood August 15, 2012 comments at 7.

187 IOUs September 10, 2012 joint comments 26.

188 IOUs September 10, 2012 joint comments 26.

basis) and participate in the CAISO market.[189] We adopt the provisions in the July 18, 2012 draft joint standard contract.

Henwood also states that, overall, SDG&E has taken a more reasonable approach to telemetry than PG&E and SCE.[190] SDG&E states, in part, at Appendix F of the draft contract that "If the nameplate rating of the Project is 1 MW or greater, a Telemetering System at the metering location may be required at the Seller's expense." Unlike SDG&E, PG&E and SCE do not provide for different requirements for telemetry based on the size of the project. Henwood suggests that the Commission direct all of the IOUs to utilize the approach proposed by SDG&E.

We find the differences between SDG&E's provision and PG&E's and SCE's provision justified by the differences in their underlying distribution and transmission systems.

Accordingly, we adopt the provisions in the July 18, 2012 draft joint standard contract.

7. The FiT Tariffs

The IOUs filed draft tariffs on July 18, 2012. Parties filed comments on these draft tariffs. In response to these comments and to a January 8, 2013 ALJ ruling seeking greater uniformity among the provisions of the IOUs' tariffs, the IOUs filed revised draft tariffs on January 18, 2013. We have reviewed these tariffs and comments. We discuss the tariffs below. The IOUs shall file a Tier 2 Advice Letter with tariffs (and the joint standard contract) consistent with the below 30 days following the effective date of this decision.

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[189] IOUs September 10, 2012 joint comments 26.

[190] Clean Coalition September 10, 2012 comments at 16-17.

7.1. Effective Date of Tariff and Initiation of Program

In the IOUs' July 18, 2012 draft tariffs, each of the three IOUs propose a different effective date for the tariffs and start date of the FiT program. Clean Coalition and SEIA express support for a uniform effective date and program start-up. SEIA identifies PG&E's proposed tariff language as providing the most certainty and expediency to the market because it includes an effective date soon after Commission approval of the tariffs and includes a timeline for expeditious receipt of PPRs following that date.[191]

PG&E's July 18, 2012 draft tariff proposes an effective date of the first day of the calendar month following the latter of: (1) Commission approval of the FiT tariff, or (2) the standard contract with applicants being allowed to submit their PPR and associated documentation five days after the latter effective date.

In the IOUs' January 18, 2013 revised tariffs, the IOUs harmonize this provision and request that the effective date of the FiT tariffs be specified by the Commission in its final decision on the tariff and that such effective date: (1) be no earlier than the date that the Commission's approval of the tariff is final and non-appealable; and (2) add an additional approximately 60 days to provide sufficient time for the IOUs to conform their tariffs and joint standard contract to the final decision and to set up their administrative processes, systems, and materials.

[191] Clean Coalition September 10, 2012 comments at 3; SEIA August 15, 2012 comments at 2.

We have considered the requests by the IOUs to allow sufficient time to implement the administration of the program and the other parties' requests to expedite implementation, and we adopt the following process:

Each IOU is ordered to file a Tier 2 Advice Letter for approval of its FiT tariffs and the joint standard contract, consistent with the terms of this decision, 30 days after the effective date of this decision. Unless the Advice Letter is suspended by the Commission, this Advice Letter (and the attached tariffs and joint standard contract) will become effective 30 days after the filing date of the Tier 2 Advice Letter (Effective Date).[192] This means that the IOUs shall begin accepting PPR for projects on and after the first business day of the month that is 60 days after the Effective Date. The IOUs shall initiate the first bi-monthly program period (Period 1) on the first business day of the month that is 90 days after the Effective Date. The FiT program shall close to new applicants upon the full subscription of total program capacity.

We find the IOUs' proposed tariff language that suggests that the Effective Date be held until the tariffs or related Commission decisions are "final and non-appealable" is unreasonably vague. Instead, the tariff provisions, revised per the above, reasonably balance the need for the IOUs to accomplish administrative tasks associated with implementation of the program with Clean Coalition's and SEIA's request to initiate the program as soon as possible. The revised provision also achieves uniformity across the three IOUs.

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[192] As of this Effective Date, IOUs must no longer accept contracts under the AB 1969 FiT program.

In addition, SDG&E suggests that the Commission address at what point the IOUs must stop accepting contracts under the AB 1969 program.[193] We agree that additional clarification on this matter would be helpful. On the effective date of the new tariffs, the IOUs shall no longer accept contracts under the AB 1969 program.

Accordingly, the IOUs are directed to remove the language relating to postponing the tariff effective date until matters are "final and non-appealable." from their January 18, 2013 draft tariffs. With that revision, we adopt the language in the January 18, 2013 draft tariffs regarding effective date. We also adopt the January 18, 2013 draft tariff language on PPRs and program periods, revised in accordance with the above to compress the timeframe until the start of the first bi-monthly program period.

7.2. Developer Experience

Regarding the provision of the tariff on Developer Experience (which is part of the Project Viability Criteria adopted in D.12-05-035), Reid states that PG&E's interpretation of Developer Experience, as requiring a member of the development team to have completed at least one project sized no more than one megawatt smaller than the proposed project, is overly restrictive. D.12-05-035 requires a showing to establish developer experience in the industry. One option for satisfying this showing includes the developer attesting that one member of the development team has completed at least one project of

[193] SDG&E April 8, 2013 comments at 11.

similar technology and capacity.[194] Reid states that PG&E's distinction should be deleted as little difference exists between the complexity of a 1 MW project and, for example, a 3 MW project.[195] We agree that PG&E's interpretation of this provision is overly restrictive. In the revised tariffs dated January 18, 2013, the IOUs harmonized this provision and addressed Reid's concern by proposing that:

> A project less than 1 MW will be deemed to be similar capacity to a Project up to 1 MW. A project between 1 MW to 3 MW will be deemed to be a similar capacity to a Project up to 3 MW. For example, for a 3 MW Project, a project of similar capacity cannot be smaller than 1 MW.

We find the IOUs revised and harmonized provision satisfies the Developer Experience requirement (Project Viability Criteria) adopted in D.12-05-035 by reasonably balancing the need to promote administrative ease and the success of projects. Accordingly, this revised provision is adopted.

7.3. Cure Period for Deficient Program Participation Requests

Clean Coalition and SEIA state that a uniform method of addressing incomplete PPRs across the three IOUs would minimize confusion in the market. They prefer SCE's proposed process for addressing incomplete PPRs and suggest it should be required for all three IOUs.[196] In the initial tariff filings dated July 18, 2012, each of the IOUs proposed a unique process for addressing

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[194] D.12-05-035 at 69.

[195] Reid August 15, 2012 comments at 9.

[196] Clean Coalition September 10, 2012 comments at 5.

incomplete PPRs. SCE would afford the applicant, upon notice from SCE, 10 business days to cure the deficiency. PG&E would afford the applicant five business days. In contrast, SDG&E does not provide for a definitive cure period but simply states that if the PPR is incomplete, then the applicant will be asked to resubmit.

In the revised tariffs filed on January 18, 2013, the IOUs harmonized this provision and proposed a 10 business day period for applicants to cure a deficiency in a submitted PPR but limits the cure period to "minor" deficiencies so that parties do not misuse this cure period by knowingly submitting an incomplete PPR to secure a higher FiT program number.

Consistency among the IOUs on this topic promotes a streamlined program. Furthermore, a relatively short and definitive time period for resubmission of deficient PPRs ensures that deficiencies in the PPR are more in the realm of a minor technicalities rather than overarching substantive problems with project eligibility. The uniform proposal set forth in the IOUs' January 18, 2013 revised tariffs, which allows ten business days to cure a deficiency, achieves the right balance between providing the developer sufficient time to correct the noted shortcoming in its PPR and assuring that the cure period does not become a period in which to attempt overhauling a project to meet eligibility requirements. We adopt the IOUs' revised proposal, as noted in the January 18, 2013 filings, for all three IOUs.

7.4. Process to Confirm a FiT Eligible Electric Generation Facility

Clean Coalition states that the method used by IOUs to confirm that an applicant's generation facility meets all the requirements to be a FiT Eligible Electric Generation Facility should be specified.[197] For example, Clean Coalition points out that SCE's July 18, 2012 draft tariff (Special Conditions - Section 1) provides that "…SCE will confirm whether the applicant's Program Participation Request is complete" but SCE does not elaborate upon this confirmation process.

In the January 18, 2013 draft tariffs, SCE and the other IOUs harmonized this provision of their tariffs. The IOUs also added the language, "in its sole discretion." The relevant excerpt from SDG&E's January 18, 2013 tariff is below:

> Review Period and Re-MAT Queue Number Assignment: Within twenty (20) business days of receiving a PPR, SDG&E, in its sole discretion, will confirm whether the Applicant's PPR is deemed complete and satisfies the Eligibility Criteria. Applicants will be assigned a program position (Re-MAT Queue Number) once the PPR is deemed complete. If the PPR is deemed complete, the Re-MAT Queue Number assignment will be based on the date and time that the PPR was received by SDG&E.

We will refrain from requiring IOUs to incorporate a more specific process for confirming that an applicant's generation facility meets all the requirements to be a FiT Eligible Electric Generation Facility. We permit the IOUs some flexibility in implementing and establishing this process because this result reasonably balances our goal of streamlining the program by placing responsibility for some implementation details in the hands of the IOUs, which

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[197] Clean Coalition September 10, 2012 comments at 5-6.

know their internal processes best, with our goal of program transparency. At this time we impose no further requirements on IOUs for this confirmation process.

Accordingly, the above tariff language is adopted.

7.5. Non-Disclosure Agreement

Clean Coalition states that the requirement in SCE's July 18, 2012 draft tariff (Special Conditions 1 - Section 1) that requires an applicant to submit an executed non-disclosure agreement as part of an applicant's PPR is not needed.[198]

The IOUs' January 18, 2013 draft tariffs removed this provision. It is unclear what information this non-disclosure agreement sought to protect. The IOUs do not address this matter in their January 18, 2013 filings accompanying the tariffs. For these reasons, we agree with Clean Coalition that a non-disclosure agreement is not needed.

Accordingly, the January 18, 2013 draft tariff provision (without reference to a non-disclosure agreement) is adopted. The IOUs must not require a non-disclosure agreement as part of establishing eligibility to participate in the program.

7.6. Re-Study Requirement and Loss of FiT Program Number

Clean Coalition states that an applicant should not lose its FiT program number if the applicant must engage in the restudy process to further

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[198] Clean Coalition September 10, 2012 comments at 6.

interconnection.[199] Clean Coalition refers to SCE's July 18, 2012 draft tariff (Special Condition - Section 1) and requests this provision be stricken.[200] The language in SCE's tariff appears to result in the loss of a FiT program number if the applicant no longer meets any program eligibility requirements, one of which is having obtained an interconnection study or the equivalent. A similar term is found in PG&E's July 18, 2012 tariff.[201] In support of its request, Clean Coalition states that D.12-05-035 did not find that the re-study process would result in the loss of a FiT program number and that this requirement introduces an unacceptable level of risk to the process.[202]

In the IOUs' January 18, 2013 revised tariffs, this reference to the "restudy" process is removed but the relevant tariff provision continues to state that failure to meet the eligibility requirements (one of which is an interconnection or equivalent) results in the loss of the FiT program number.

> Change in Eligibility: If an Applicant and/or Project previously deemed eligible to participate in E-ReMAT no longer meets the Eligibility Criteria, the Applicant must immediately notify PG&E and shall relinquish its E-ReMAT Queue Number for the applicable PPR. The PPR will be deemed to be rejected, as described in Program Participation Request, Section E.1.e. above.

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[199] We prefer to refer to this term as "FiT program number" while SCE's July 18, 2012 tariff refers to the term as "ReMAT Program Number."

[200] Clean Coalition September 10, 2012 comments at 6.

[201] Clean Coalition September 10, 2012 comments at 10.

[202] Clean Coalition September 10, 2012 comments at 6.

With the removal of the specific reference to the "restudy" process, Clean Coalition's concern may be addressed. We acknowledge that disputes may arise regarding an applicant's subsequent non-compliance with the program requirements, such as the interconnection study requirement, but find that, in the interest of tariff provisions with predictable outcomes, we will refrain from addressing a problem until one is presented to us.

7.7. Participation in Other Incentive Programs

Clean Coalition refers to both SCE's and PG&E's July 18, 2012 tariff and suggests that the restrictions on participation in FiT and either the California Solar Initiative (CSI) or the Small Generator Incentive Program (SGIP) be clarified as applying to generators rather than the owners of the generators.[203] We also take this opportunity to clarify the application of the restrictions on participation in net-energy metering (NEM). D.12-05-035 states that eligible electric generation facilities receiving service under FiT must first terminate participation in any NEM program for the same facility seeking service under FiT. D.12-05-035 further states that a generator that previously received incentives under CSI or SGIP can participate in FiT after it has been online and operational for at least 10 years from that date. Section 399.20(k) states that owners must refund any incentives. We clarify that the restrictions on participation in NEM, SGIP, and CSI apply to individual generators but the owner of the generator is ultimately responsible for remitting any necessary refund. We find that this interpretation facilitates broad participation in the FiT

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[203] Clean Coalition September 10, 2012 comments at 7 and 9.

program and promotes administrative ease in determining the qualification of the entity seeking to participate in FiT.

Accordingly, the IOUs are directed to modify their tariffs to clarify that these restrictions on SGIP, NEM, and CSI are applicable to each generator, not the owner but that the owner is ultimately responsible for any refunds required.

7.8. Uniform Process for Subscription to FiT Price

SEIA states that the Commission should adopt a uniform method for the IOUs' acceptance of the price and execution of the standard PPA.[204] The IOUs' July 18, 2012 draft tariffs propose different procedures for acceptance of price and execution of the joint standard contract by an applicant. SEIA suggests the Commission adopt SDG&E's proposed process, which is a more streamlined version of processes proposed by SCE and PG&E. The IOUs' January 18, 2013 draft tariffs harmonized this process and they propose a streamlined version that reflects the July 18, 2012 proposal by SDG&E. The revised and uniform proposals present a straightforward means of implementing the subscription process and responds to the concern of lack of uniformity raised by SEIA. Accordingly, we adopt the proposed language as set forth in the IOUs' January 18, 2013 draft tariffs.

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[204] SEIA August 15, 2012 comments at 7-8.

7.9. Clarification of Miscellaneous Tariff Provision

The below includes clarification to a miscellaneous tariff provision:

(1) Regarding the tariff language on the pricing structure, known as ReMAT, the IOUs are directed to clarify that, when establishing whether five different applicants exist for purposes of applying the ReMAT price adjusting mechanism, the IOUs should make this determination at the beginning of a bi-monthly period, as opposed to the end of the prior bi-monthly period.

8. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on April 8, 2013 and reply comments were filed on April 15, 2013. To the extent required, revisions have been incorporated to reflect the substance of these comments.

In addition, parties raised in comments whether submission of an advice letter is the appropriate means for a utility to seek authorization to procure beyond the capacity allocation for its tariffs as set forth in D.07-07-027.

We note that in D.07-07-027 the Commission authorized the IOUs to voluntarily procure megawatts in excess of the capacity allocation targets for their FiT tariffs. In that decision, the Commission authorized the IOUs to file an advice letter for such excess procurement. Accordingly, this process is available

to evaluate the projects above the capacity allocation for SCE's Schedule CREST, which were filed in Advice Letter 2870-E/E-A.[205]

9. Assignment of Proceeding

Mark J. Ferron is the assigned Commissioner and Regina M. DeAngelis is the assigned ALJ in this proceeding.

Findings of Fact

1. In many instances, too few megawatts would be offered by the IOUs under the megawatt allocation process adopted in D.12-05-035, which may hinder the advancement of the program by providing insufficient opportunities for eligible projects.
2. It is reasonable to modify aspects of the ReMAT mechanism to prevent unreasonable price increases and promote administrative ease.
3. D.12-05-035 is unclear on how megawatts are added back into the FiT program after a change in circumstances, including, but not limited to, the termination of a project.
4. D.12-05-035 requires modification to indicate whether subscriptions beyond the allocated megawatts for a product type for each program period are permitted.

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[205] We are aware that SCE has filed AL 2870-E (filed March 26, 2013) and AL 2870-E-A (filed April 22, 2013) citing the process established in D.07-07-027 for obtaining Commission review by an advice letter for FiT projects procured beyond the approved capacity allocation.

5. Assigning a random program number to applications received within the first 5 business days of the program will minimize impact of any technical concerns.

6. D.12-05-035 is unclear as to whether generators have the option to choose to interconnect under Rule 21 or WDAT.

7. Implementing the seller concentration provision adopted in D.12-05-035 as a Project Viability Criterion is a complex undertaking.

8. Insufficient justification exists to modify D.12-05-035 to: (1) rely on the generator's interconnection queue number when determining the FiT program number, and (2) remove the restriction on participation in RAM.

9. Insufficient justification exists to modify D.12-05-035 to:

(1) add additional megawatts into the FiT program above the amount allocated by statute;

(2) include a price floor in the ReMAT pricing;

(3) include a locational adder in the price as referenced in § 399.20(e) to capture the benefits of grid planning and procurement methodology;

(4) add environmental compliance costs to the price, as set forth in § 399.20(d)(1);

(5) refine the definition of "strategically located," as referenced in § 399.20(b)(3) to, among other things, account for a piece of equipment sometimes needed for interconnection of a project, a Direct Transfer Trip; and

(6) extend the COD due to unpredictable interconnection delays.

10. The draft FiT joint standard contract is lengthier than the existing FiT contracts because all relevant materials, such as attachments and forms, for each IOU are combined into one single document rather than three documents.

11. The Commission's use of standard contracts promotes a streamlined regulatory process.

12. Clean Coalition's proposed FiT contract, referred to as a "model contract," to be used in lieu of the draft FiT joint standard contract, was submitted late in the consideration of this issue and submitted in a manner that can be viewed as inconsistent with the process adopted by the ALJ and Assigned Commissioner.

13. The FiT program, which includes the joint standard contract, is efficient and streamlined. For now, a separate contract for smaller projects, 500 kW or less, is not needed.

14. Many issues specific to bioenergy will be addressed when the Commission implements SB 1122.

15. D.12-05-035 adopted a COD of 24 months plus a 6-month extension.

16. The draft contract requires the seller to provide 60-day notice to the buyer before COD so that the buyer can make necessary arrangements for the scheduling of power and other administrative functions.

17. The draft contract's damages provisions associated with the failure to meet the Guaranteed Commercial Operation Date do not hinder financing.

18. Frequently changing key terms in contracts, such as the seller updating Contract Quantity each year, results in excessive uncertainty.

19. The FiT program does not include a 25-year contract term.

20. Collateral requirements in the FiT program should apply as long as ratepayers continue to be at risk.

21. Monthly billing is a requirement in other programs and no evidence exists that monthly billing imposes an undue burden on sellers in the FiT program.

22. As noted in the October 5, 2012 Assigned Commissioner's Ruling, review of the term "green attributes" will take place during our overall review of the RPS procurement process in this proceeding.

23. No evidence exists to support a requirement that PG&E and SDG&E conform to SCE's proposal and act as the QREs for WREGIS purposes for all FiT projects. Certain exceptions exist for smaller projects.

24. The FiT program provides the developers with various options regarding seeking Fully Deliverable status.

25. A cap of the costs associated with complying with changes in the law during the term of the contract is needed to share the risk of those costs.

26. The FiT program offered under the draft joint standard contract is only available to sellers that are QFs. Sellers are responsible for completing all necessary documents with FERC.

27. Section 5.3.2 of the draft FiT joint standard contract is sufficiently clear.

28. Section 5.3.8 of the draft FiT joint standard contract appropriately applies to sellers, as potentially the less sophisticated party.

29. Section 5.3.9 of the draft FiT joint standard contract does not prohibit or even address sales to buyers not covered by the FiT program.

30. Section 5.3.12 and 5.3.13 of the draft FiT joint standard contract promote administrative ease by providing a reasonable means of ensuring that FiT contracts proceed in an expeditious and non-controversial fashion.

31. The safety related benefits derived from maintaining a daily log of material operations and maintenance by sellers outweighs the burdens of this requirement.

32. Section 6.12 of the draft FiT joint standard contract provides a reasonable balance between ensuring the timely exchange of information between the contracting parties to support efficient and safe transactions and streamlining the contracting process to meet the specific needs of FiT developers.

33. Section 6.12.3 of the draft FiT joint standard contract is not overly burdensome but, instead, it achieves a reasonable balance between the buyer's need for information to ensure compliance with laws related to WMDVBE and the seller's need to assist with the compliance of such laws.

34. IOUs should not pay for any work related to the IOUs' requests to sellers related to WMDVBE.

35. By requiring the seller to obtain the buyer's consent before making any modifications to its facility, Section 6.14 of draft FiT joint standard contract imposes an unreasonably vague burden on the seller. The benefits, if any, of such a requirement are outweighed by the goal of streamlining the contracting process for projects under the FiT program. Buyer's consent of material modifications promotes the interests of the contracting parties.

36. The insurance provisions in Section 10 of the draft FiT joint standard contract are appropriate based on the risks to ratepayers throughout the contracting term.

37. The record is currently insufficiently developed on the issue that Section 11 of the draft FiT joint standard contract (the 1-year period for Force Majeure that triggers contract termination) does not appropriately take into consideration Force Majeure events at dairy and other biogas projects, such as catastrophic animal disease.

38. No evidence exists that Section 12 of the draft FiT joint standard contract, Guaranteed Energy Production, hinders seller financing. Instead, the provision reasonably balances the buyer's and seller's interests.

39. Consistent with D.11-11-012, appropriate protections are afforded by a lower amount for project development security, $20/kW for all eligible FiT projects, and IOUs should be allowed to maintain the collateral requirement through the term of the contract.

40. The letter of credit requirements in the draft FiT standard contract reasonably balance the need to protect ratepayers from risk of loss with the need to provide developers with increased access to more banks in order to secure financing.

41. No new evidence was presented regarding the reasonableness of the termination rights set forth in Section 14.9 of the draft FiT joint standard contract that refer to Network Upgrade Costs exceeding $300,000.

42. The 60 days provision in Section 14.9 of the draft FiT joint standard contract is a reasonable balance between the desire for certainty by the parties regarding the terms of the transaction, verifying transmission costs, and researching options available to the parties going forward.

43. Providing the seller with the option of paying the buyer a reasonable fee for the forecasting service furthers our goal of streamlining the FiT contracting process by reducing the burden on the small developers without subjecting ratepayers to additional costs or risks.

44. IOUs are operating within the law in recording conversations, as set forth in Section 16.2 of the draft FiT joint standard contract and the recording of conversations is a reasonable means of minimizing disputes involving and managing the public safety aspects of scheduling energy.

45. Because assignment transfers all the rights and responsibilities to a third-party, we find reasonable the need set forth in Section 17 of the draft FiT joint standard contract to obtain the consent of buyer rather than just notifying buyer.

46. Section 17 of the draft FiT joint standard contract, as revised herein, promotes administrative ease by reasonably balancing the seller's need for flexibility to assign the contract with the buyer's need to ensure that the assignee is able to perform as required under the contract.

47. Consent to assignment should not be unreasonably withheld.

48. The arbitration provision in Section 19.1 of the draft FiT joint standard contract reasonably balances the goal of streamlining the administration of FiT contracts with providing the opportunity to successfully develop projects.

49. The objectives of a standard contract are, generally, to promote administrative ease, reduce transaction costs, and protect the rights of the parties and, if amendments are permitted to the FiT joint standard contract, on even seemly minor matters, our efforts to balance these objectives may be compromised.

50. No amendments to the FiT joint standard contract will be permitted, with the exception of administrative amendments, unless Commission approval of the contract, as modified, is obtained.

51. The IOUs' proposal that FiT projects under 500 kW aggregate telemetry costs and to limit those costs with a $20,000 cap balances the CAISO's need for visibility of these generators with the developer's need to limit costs on telemetry. The differences between SDG&E's provision versus PG&E's and SCE's provision is based on differences in their underlying distribution and transmission systems.

52. The language in the January 18, 2013 draft tariffs that the tariff shall become effective when "final and non-appealable" is unreasonably vague.

53. The January 18, 2013 draft tariff provision satisfies the Developer Experience requirement (Project Viability Criteria) adopted in D.12-05-035 by reasonably balancing the need to promote administrative ease and the success of projects.

54. The uniform proposal set forth in the IOUs' January 18, 2013 tariffs, which allows 10 business days to cure a "minor" deficiency in a PPR, achieves the right balance between providing the developer sufficient time to correct the noted shortcoming and assuring that the cure period does not become a period in which generators attempt to overhaul a project to meet eligibility requirements.

55. Permitting the IOUs some flexibility in implementing and establishing a process for determining whether an applicant's generation facility meets all the requirements to be a FiT Eligible Electric Generation Facility reasonably balances our goal of streamlining the program by placing responsibility for some implementation details in the hands of the IOUs, which know their internal processes best, with our goal of transparency.

56. No evidence exists that the IOUs should require a non-disclosure agreement as part of establishing eligibility to participate in the program.

57. Applicant should not lose its FiT program number because it must engage in a re-study process as part of its interconnection process but other factors may lead to this result; the draft FiT joint standard contract reasonably establishes a process by which eligibility may be maintained if the applicant, not ratepayers, fund any network upgrades exceeding $300,000 resulting from any re-study process.

58. To properly implement § 399.20(k), which states that owners must refund any incentives, the restrictions on participation in NEM, SGIP, and CSI applies to individual generators but the owner of the generator is ultimately responsible for remitting any necessary refund.

59. The IOUs' January 18, 2013 draft tariffs present a straightforward means of implementing the subscription process.

60. D.07-07-027 stated that utilities could voluntarily purchase energy consistent with the FiT program from projects beyond the capacity allocation.

61. D.07-07-027 required Commission review, via advice letter, of utility purchases of FiT program energy beyond the capacity allocation.

62. SCE's Advice Letter 2870-E/E-A seeks Commission approval of FiT contracts beyond the capacity allocation.

Conclusions of Law

1. The July 31, 2012 *Petition of the Solar Energy Industries Association for Modification of Decision 12-05-035* and the November 13, 2012, *Clean Coalition and California Solar Energy Industries Association Petition for Modification of D.12-05-035* should be granted, in part. As a result, the process used by IOUs to offer megawatts during each bi-monthly period should be modified as described herein in an effort to make more megawatts available earlier in the program.

2. The ReMAT mechanism should be modified to protect against unreasonable price increases and to promote administrative ease.

3. A total price period adjustment cap of $12 should be adopted.

4. Certain conditions for triggering a price adjustment should be modified such that a price decrease is triggered if the total capacity of the projects for which the applicants have indicated they would be willing to execute a ReMAT PPA based on the applicable contract price for a period is at least 100% of the

capacity allocation for that period; and a price increase is triggered if the total capacity of the projects for which applicants have indicated a willingness to execute a ReMAT PPA based on the applicable contract price for a period is less than 20% of the capacity allocation for that period.

5. The duration of the program should remain fixed, but D.12-05-035 should be modified to establish the end date at 24 months after the first product type goes to zero MW or goes to a *de minimis* amount approaching zero.

6. D.12-05-035 should be clarified such that each IOU should publicly notice on the first business day of each bi-monthly program period, and on the date that the tariffs and standard contracts adopted herein are effective, the number of megawatts that will be offered in the next bi-monthly period for each product type, the number of megawatts remaining for each product type, and the total number of megawatts remaining in the IOU's FiT program.

7. The July 31, 2012 *Petition of the Solar Energy Industries Association for Modification of Decision 12-05-035* should be granted in part. As a result, the process for adding megawatts back into the FiT program after a change in circumstances, including, but not limited to, the termination of a project, is clarified to require IOUs to place the megawatts back into the product type of the terminated project unless the terminated project was initiated under the D.07-07-027 and AB 1969 program, in which case, IOUs should be required to place the megawatts back into the IOU's total program capacity to be equally divided among the three product types.

8. The July 31, 2012 *Petition of the Solar Energy Industries Association for Modification of Decision 12-05-035* should be granted in part. As a result, D.12-05-035 should be modified to include the requirement that subscriptions beyond the allocated amount will not be permitted.

9. The July 31, 2012 *Petition of the Solar Energy Industries Association for Modification of Decision 12-05-035* should be granted in part. As a result, D.12-05-035 should be clarified to mean that if both federal and state interconnection tariffs are applicable in a given situation, the developer is permitted to choose whether to proceed under Rule 21 or the federal wholesale tariffs until the Commission makes a determination otherwise.

10. The July 31, 2012 *Petition of the Solar Energy Industries Association for Modification of Decision 12-05-035* should be granted in part. As a result, D.12-05-035 should be modified to remove the seller concentration provision as it is overly complex to implement.

11. The July 31, 2012 *Petition of the Solar Energy Industries Association for Modification of Decision 12-05-035* should be denied, in part, as insufficient justification exists to modify D.12-05-035 to: (1) rely on the generator's interconnection queue number when determining the FiT program number, and (2) remove the restriction on participation in RAM.

12. The November 13, 2012 *Clean Coalition and California Solar Energy Industries Association Petition for Modification of D.12-05-035* should be denied as to the following requests:

(1) add additional megawatts into the FiT program above the amount allocated by statute;

(2) include a price floor in the ReMAT pricing;

(3) include a locational adder to the price;

(4) add environmental compliance costs to the price, as set forth in § 399.20(d)(1);

(5) refine the definition of "strategically located," as referenced in § 399.20(b)(3) to, among other things, account for a piece of equipment sometimes

needed for interconnection of a project, a Direct Transfer Trip; and

(6) extend the COD due to unpredictable interconnection delays.

13. The length of the FiT joint standard contract is reasonable because, while the joint contract is now longer than any one of the IOU's pre-existing contracts, the benefits of a single joint standard contract instead of three separate contracts are significant.

14. The use of a standard contract for the FiT program is reasonable as it promotes a streamlined regulatory process.

15. The cost of power procured by PG&E, SCE, and SDG&E through the tariffs/standard contracts authorized by this decision and D.12-05-035 (as modified by D.13-01-041) are reasonable and recoverable in rates subject to Commission review of the administration of these contracts.

16. The contract filed by Clean Coalition on August 15, 2012, referred to as a "model contract," should be denied.

17. The draft FiT joint standard contract should not be modified to reflect specific characteristics of bioenergy projects because more record development is needed and these matters will be appropriately addressed when the Commission implements SB 1122.

18. Changes to the COD adopted in D.12-05-035 are not reasonable except to require a single 6-month extension because no new information was otherwise presented.

19. It is reasonable to request that the seller provide 60-day notice to the buyer before COD so that the buyer can make necessary arrangements for the scheduling of power and other administrative functions.

20. The draft contract's provision related to damages for failure to meet the Guaranteed Commercial Operation Date appropriately balances the need to protect ratepayers from project failure by including actual damages when the party fails to perform and our effort to streamline project financing by clearly stating the potential costs associated with the contract.

21. The FiT program offers a 5, 10, and 20-year contract term and it is not reasonable to offer a 25-year contract term because § 399.20 does not include a 25-year contract term.

22. It is reasonable to maintain collateral requirements after the COD because ratepayers continue to be at risk.

23. Monthly billing is reasonable because, while developers may gain slight administrative efficiencies from longer billing periods, greater benefits will be achieved over the term of the contract with the more frequent monthly billing.

24. Review of the *green attributes* term is more appropriately addressed during the Commission's overall review of the RPS procurement process in this proceeding.

25. Based on differences in their internal processes, it is not reasonable to require PG&E and SDG&E to conform to SCE's proposal and act as the QREs for WREGIS purposes for all of their FiT projects.

26. Developers have the option to seek Fully Deliverable status. Developers are obliged to follow the rules of other jurisdictions, such as the CAISO, and to obtain Fully Deliverable status if not burdensome.

27. The Compliance Expenditure Cap of $25,000 yearly for costs related to changes in CEC Pre-Certification, CEC Certification or CEC Verification during the term of the contract and pertaining to ensuring the energy is from an eligible renewable energy resource is reasonable.

28. Sellers should formally obtain QF status through FERC to reduce the uncertainties in the contracting process.

29. Because Section 5.3.2 of the draft FiT joint standard contract is sufficiently clear, it is not necessary to clarify how the provision applies to hydro projects.

30. Section 5.3.8 of the draft FiT joint standard contract does not need modification because the provision should not also be applicable to buyers.

31. Section 5.3.9 of the draft FiT joint standard contract does not need modification because the provision does not prohibit sales to other buyers.

32. Section 5.3.12 and 5.3.13 of the draft FiT joint standard contract do not need modification as these terms promote administrative ease by providing a reasonable means of ensuring that FiT contracts proceed in an expeditious and non-controversial fashion.

33. Section 6.5.1 of the draft FiT joint standard contract does not require modification because the safety related benefits derived from maintaining a daily log of material operations and maintenance by sellers outweighs the burdens of this requirement.

34. Section 6.12 of the draft FiT joint standard contract does not require modification because the provision provides a reasonable balance between ensuring the timely exchange of information between the contracting parties to support efficient and safe transactions and streamlining the contracting process to meet the specific needs of FiT developers.

35. Section 6.12.3 of the draft FiT joint standard contract does not require modification because the provision is not overly burdensome but, instead, it achieves a reasonable balance between the buyer's need for information to ensure compliance with laws related to WMDVBE and the seller's need to assist with the compliance of such laws.

36. Section 6.14 of the draft FiT joint standard contract, which requires the seller to obtain the buyer's consent before making any modifications to its facility, should be removed as the provision imposes an unreasonably vague burden on the seller. The contact provision recommended by SCE which only requires buyer's consent when the modification is material is reasonable as it protects the interests of the contracting parties.

37. The insurance provisions in Section 10 of the draft FiT joint standard contract do not require modification, except to provide the seller with 60 days to provide evidence of insurance, because the provisions reasonably reflect the risks to ratepayers throughout the contracting term.

38. It is reasonable to review Section 11 of the draft FiT joint standard contract (the 1-year period for Force Majeure that triggers contract termination) in the proceeding when the Commission implements SB 1122.

39. Section 12 of the draft FiT joint standard contract, Guaranteed Energy Production, does not require modification as the provision reasonably balances the buyer's need to have a high level of certainty regarding the expected generation and the seller's need for flexibility to account for unknowns by permitting a specific amount of over- or under-generation.

40. It is reasonable to require Section 13 of the draft FiT joint standard contract be modified, consistent with D.11-11-012, to include a lower amount for project development security, $20/kW for all eligible FiT projects, and allow IOUs to maintain the collateral requirement through the term of the contract.

41. The letter of credit requirements in Section 13.6 of the draft FiT joint standard contract should be modified to reasonably balance the need to protect ratepayers from risk of loss with the need to provide developers with increased access to more banks in order to secure financing.

42. The 60 days provision in Section 14.9 if the draft FiT joint standard contract does not require modification because it reasonably balances the desire for certainty by the parties regarding the terms of the transaction, verifying transmission costs, and researching options available to the parties going forward.

43. It is reasonable to modify Section 15 and Appendix D of the draft FiT joint standard contract to provide sellers with the option of paying buyer a reasonable fee for the forecasting service as this outcome furthers the Commission's goal of streamlining the FiT contracting process by reducing the burden on the small developers without subjecting ratepayers to additional costs or risks.

44. Section 16.2 of the draft FiT joint standard contract should not be modified because IOUs are operating within the law in recording conversations and recording of conversations is a reasonable means of minimizing disputes involving and managing the public safety aspects of scheduling energy.

45. Section 17 of the draft FiT joint standard contract does not require modification because it promotes administrative ease by reasonably balancing the seller's need for flexibility to assign the contract with the buyer's need to ensure that the assignee is able to perform as required under the contract. Consent to assignment should not be unreasonably withheld.

46. The arbitration provision in Section 19.1 of the draft FiT joint standard contract does not require modification as it reasonably balances the goal of streamlining the administration of FiT contracts with providing developers the opportunity to successfully develop projects.

47. The draft FiT joint standard contract should be modified, including Section 20.3, so that no amendments to the contract are permitted, with the

exception of administrative amendments, unless Commission approval of the contract, as modified, is obtained.

48. No modification to Appendix F of the draft FiT joint standard contract is required as the IOUs' proposal to aggregate the telemetry costs for projects under 500 kW aggregate and to limit those costs with a $20,000 cap is a reasonable means of achieving the CAISO's need for visibility of these generators by providing the data needed so that these small generators can be scheduled (on an aggregate basis) and participate in the CAISO market.

49. The tariff will become effective consistent with the rules applicable to Tier 2 Advice Letters. Upon the effective date of the tariff, no contracts will be accepted under the AB 1969 FiT tariffs.

50. The unreasonably vague language in the January 18, 2013 draft tariffs that the tariff shall become effective when "final and non-appealable" should be removed.

51. The January 18, 2013 draft tariff provision on Developer Experience (Project Viability Criteria) is reasonable as it is consistent with D.12-05-035.

52. The proposal set forth in the IOUs' January 18, 2013 draft tariffs, which allows 10 business days to cure a "minor" deficiency in a PPR, reasonably balances the need to provide the developer sufficient time to correct the noted shortcoming in its PPR and to assure that the cure period does not become a period in which to attempt overhauling a project to meet eligibility requirements.

53. The proposal set forth in the IOUs' January 18, 2013 draft tariffs, permitting the IOUs some flexibility in implementing and establishing a process for determining whether an applicant's generation facility meets all the requirements to be a FiT Eligible Electric Generation Facility reasonably balance the goal of streamlining the program by placing responsibility for some

implementation details in the hands of the IOUs, which know their internal processes best, with the goal of program transparency.

54. The January 18, 2013 draft tariff language without reference to a non-disclosure agreement is reasonable as no evidence exists that IOUs should require a non-disclosure agreement as part of establishing eligibility to participate in the program.

55. It is reasonable to remove the provision in the IOUs' January 18, 2013 draft tariffs that references the "restudy" interconnection process. If the "restudy" interconnection process shows that the project requires network upgrades exceeding $300,000, Section 14.2 of the draft FiT standard contract ensures that ratepayers bear no risk associated with such excess costs.

56. To facilitate broad participation in the FiT program and promote administrative ease in determining the qualification of the entity seeking to participate in FiT, it is reasonable to find that restrictions on NEM, SGIP, and CSI apply to individual generators but the owner of the generator is ultimately responsible for remitting any necessary refund.

57. The language in the IOUs' January 18, 2013 draft tariffs which harmonized the process for subscription to the FiT price is reasonable as it presents a straightforward means of implementing the subscription process.

58. An Advice Letter is appropriate for review of utility requests to voluntarily purchase energy under the FiT program beyond the capacity allocation.

59. The Advice Letter process is appropriate for SCE's Advice Letter 2870-E/E-A.

O R D E R

IT IS ORDERED that:

1. The Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file a Tier 2 Advice Letter for approval of the § 399.20 Feed-In Tariff (FiT) joint standard contract and tariffs 30 days after the effective date of this decision. The FiT joint standard contract shall be consistent with the July 18, 2012 filing as modified herein. The FiT tariffs shall be consistent with the January 18, 2013 filings as modified herein.
2. The July 31, 2012 *Petition of the Solar Energy Industries Association for Modification of Decision 12-05-035* is granted, in part.
3. The November 13, 2012, *Clean Coalition and California Solar Energy Industries Association Petition for Modification of D.12-05-035* is granted, in part.
4. Rulemaking 11-05-005 remains open.

This order is effective today.

Dated May 23, 2013, at San Francisco, California.

MICHAEL R. PEEVEY
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
MARK J. FERRON
CARLA J. PETERMAN
Commissioners

EXHIBIT D

L/mal

Date of Issuance
April 19, 2011

Decision 11-04-033 April 14, 2011

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion into Combined Heat and Power Pursuant to Assembly Bill 1613.	Rulemaking 08-06-024 (Filed June 26, 2008)

ORDER GRANTING LIMITED REHEARING OF DECISION (D.) 10-12-055 ON THE ISSUE OF GHG COMPLIANCE COSTS, MODIFYING DECISION, DENYING REHEARING OF DECISION, AS MODIFIED, AND DENYING MOTION TO STAY

I. INTRODUCTION

Today's decision disposes of the applications for rehearing of Decision (D.) 10-12-055, filed by the Joint Utilities.[1] D.10-12-055 was issued in response to a Petition for Modification of D.09-12-042, filed by the Joint Utilities. In D.09-12-042, we adopted the policies and procedures for purchase of excess electricity from eligible Combined Heat and Power ("CHP") systems by an electrical corporation under The Waste Heat and Carbon Emissions Reduction Act, Assembly Bill 1613 (Stats. 2007, ch. 713) ("AB 1613").

On January 18, 2011, PG&E and SDG&E together filed a timely application for rehearing of D.10-12-055, and SCE separately filed a timely application for rehearing of D.10-12-055. Concurrently, the utilities jointly filed a motion for stay of D.10-12-055 until the later of resolution of the Joint Utilities' Petition for Enforcement pursuant to Section 210(h) of the Public Utility Regulatory Policies Act of 1978

[1] We refer to Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE"), and San Diego Gas and Electric Company ("SDG&E") collectively as the "Joint Utilities".

("Enforcement Petition") filed with the Federal Energy Regulatory Commission ("FERC") on January 31, 2011,[2] or the effective date of a Commission decision resolving their applications for rehearing of D.10-12-055.

Both applications for rehearing claim that the price to be paid to AB 1613 generators violates both the Public Utility Regulatory Policies Act of 1978 ("PURPA")[3] and FERC regulations because it is higher than the utilities' avoided costs and contend that the record is insufficient to support the pricing adopted by D.10-12-055.[4] Specifically, PG&E/SDG&E argue that the AB 1613 price formula exceeds avoided cost because it pays a firm price for an as-available product. (PG&E/SDG&E's Rehrg. App., at p. 2.) SCE claims the price formula exceeds avoided costs because it is higher than other avoided costs paid to other QFs with "identical relevant characteristics." (SCE's Rehrg. App., at p. 2.) Both rehearing applications also offer multiple variations on these avoided cost arguments and also claim the location bonus and the pass through of greenhouse gas ("GHG") compliance costs to the purchasing utility affirmed in D.10-12-055 violate PURPA because they do not constitute avoided cost payments. (PG&E/SDG&E's Rehrg. App., at pp. 11-13; SCE's Rehrg. App., at pp. 10-13.)

San Joaquin Refining Company, Inc. ("San Joaquin") filed a response and California Clean DG Coalition ("CCDC") and FuelCell Energy Inc. ("FuelCell") filed a joint response to the Joint Utilities' rehearing applications and their motion for stay. The Joint Utilities filed a reply to the responses on their motion for stay.

We have reviewed each and every argument raised in the rehearing applications and are of the opinion that rehearing should be granted on the limited issue

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[2] See FERC Docket No. EL11-19-000.

[3] PURPA is codified in scattered sections of 16 U.S.C. including § 796 (definitions), § 824a-3, and §§ 2601 *et seq*.

[4] FERC regulations define "avoided costs" as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." (18 C.F.R. § 292.101(b)(6).)

of the GHG compliance costs, and that modifications to D.10-12-055, as described herein, are warranted to: (1) modify our treatment of GHG compliance costs to be consistent with avoided cost principles; (2) clarify why the market price referent ("MPR") based energy price adopted by D.09-12-042 and affirmed in D.10-12-055 is consistent with avoided cost principles; (3) clarify why the 10% Location Bonus is consistent with avoided cost principles, and (4) conform D.09-12-042 with the modifications ordered by D.10-04-055 and D.10-12-055, as modified herein. Rehearing of D.10-12-055, as modified, is denied. We also deny the Joint Utilities' motion for stay as without merit.

II. BACKGROUND

A. AB 1613

AB 1613 – The Waste Heat and Carbon Emissions Reduction Act – was enacted by the California Legislature in 2007 to be effective January 1, 2008, in order to further environmental objectives, particularly the reduction of GHG emissions. AB 1613 is codified at Public Utilities Code sections 2840 through 2845.

In short, AB 1613 requires the Commission to establish a "standard tariff" for qualifying CHP generators to sell their excess electricity to the utilities. (Pub. Util. Code, § 2841, subd. (b)(1).) AB 1613 anticipates that such a program will result in multiple benefits to California because it will:

> [(a)] advance the efficiency of the state's use of natural gas by capturing unused waste heat, and in doing so, help offset the growing crisis in electricity supply and transmission congestion in the state.
>
> [(b)] reduce wasteful consumption of energy through improved . . . utilization of waste heat whenever it is cost effective, technologically feasible, and environmentally beneficial, particularly when this reduces emissions of carbon dioxide and other carbon-based greenhouse gases.

(Pub. Util. Code, § 2840.6, subds. (a) and (b).) The AB 1613 program seeks to enhance the efficiency of an existing class of industrial boilers and reduce GHG emissions by

providing incentives to install heat recovery steam generators and turbines (CHP systems) at the tail end of these existing units. AB 1613 CHPs will capture and make useful the energy already produced by boilers, which until now, had been discharged to the atmosphere as waste heat.[5] AB 1613's policy goal to reduce carbon-based emissions is part of the state's overall objective to reduce GHG emissions, as articulated in Assembly Bill 32, California's "Global Warming Solutions Act of 2006" (Stats. 2006, ch. 488) ("AB 32").[6]

To advance these goals beyond a traditional CHP program, an AB 1613 CHP must meet strict efficiency and emission requirements, including the following: at least a 60% Energy Conversion Efficiency; a nitrogen oxide (NOx) emission standard of 0.07 pounds per megawatt-hour ("MWh"); a GHG emission standard of no more than 1,100 pounds of carbon dioxide ("CO_2") equivalent emissions per MWh; and an allocation of any more stringent carbon emissions compliance costs, which the California Air Resources Board ("CARB") may adopt under AB 32, and/or which the Federal government ultimately may impose. (Pub. Util. Code, § 2843.)

AB 1613 also imposes requirements to ensure reliable and continuous onsite generation to address the state's energy supply and transmission congestion challenges. An AB 1613 CHP must be sized to meet its onsite load, must "operate continuously in a manner that meets the expected thermal load," and may only sell its excess power to the utilities. (See Pub. Util. Code, §§ 2840.2, subds. (a) and (e), 2841, & 2843, with quotation from § 2843, subd. (a)(2).) In exchange, the entire physical generating capacity of the AB 1613 CHP, not just the excess energy sold to the utility, counts towards the purchasing utility's resource adequacy obligations. (Pub. Util. Code, § 2841, subd.(f).)

[5] This process and logic can be used to describe either topping-cycle or bottoming-cycle CHP; the policy goal to maximize the use of waste heat applies to both.

[6] AB 32 requires, among other things, that the California Air Resources Board adopt a statewide GHG emissions limit equivalent to the statewide GHG emissions levels in 1990, to be achieved by 2020, in consultation with this Commission and the California Energy Commission.

B. Commission Implementation of AB 1613

Rulemaking (R.) 08-06-024 was opened to develop the policies and procedures for the utilities to purchase excess electricity from AB 1613 CHPs pursuant to a standard tariff. The AB 1613 program has been very controversial because of the utilities' objections to a standard tariff that establishes a fixed price for purchases, also known as a "fixed price feed in tariff" or "FIT". Consequently, the utilities have opposed implementation of AB 1613 at the Commission and before FERC.

The Commission has now adopted three decisions in its efforts to implement the FIT portion of AB 1613: (1) D.09-12-042 initially implementing the AB 1613 program; (2) D.10-04-055 denying rehearing of D.09-12-042, as modified, to clarify certain discussions; and (3) D.10-12-055, granting in part, and denying in part, a Joint Utilities' petition for modification of D.09-12-042 (together "CHP decisions").[7] This last decision modified D.09-12-042 to implement the AB 1613 program pursuant to PURPA and consistent with two FERC orders issued after the Commission's adoption of D.10-04-055. However, D.10-12-055 ordered very few specific modifications to D.09-12-042, and most of those modifications were focused on contract terms. The modifications did not reflect the changed legal status of the program to a PURPA/Qualifying Facility ("QF") program. The history of these changes is described in more detail below.

The Commission adopted D.09-12-042 on December 17, 2009. On January 20, 2010, the Joint Utilities together filed an application for rehearing of D.09-12-042 on the grounds that its adopted price formula was preempted by federal law and violated the ratepayer indifference standard of AB 1613. On the same day, the Joint Utilities also filed a motion for stay, and the Alliance for Retail Energy Markets ("AReM") also filed a rehearing application of the same decision. San Joaquin, CCDC, AReM and the Division

[7] A fourth decision, D.11-01-010, was issued to address the "Pay as You Go" issues raised in the proceeding. That decision closed the proceeding.

of Ratepayer Advocates ("DRA") filed responses to the Joint Utilities' application for rehearing. San Joaquin and CCDC/FuelCell filed a response to the Joint Utilities' stay motion, and PG&E and DRA filed a response to AReM's rehearing application.

On February 2, 2010, the Joint Utilities timely filed a Joint Petition for Modification of D.09-12-042 ("Joint Utilities' PFM"). The Joint Utilities claimed to be seeking resolution of alleged problems with the implementation of D.09-12-042 as it stood at that time. San Joaquin, CCDC, FuelCell, and The Utility Reform Network ("TURN")/DRA filed comments on the Joint Utilities' PFM.

On April 26, 2010, the Commission issued D.10-04-055 denying both applications for rehearing and clarifying, through modifications, certain aspects of D.09-12-042.

On May 4, 2010, the Commission submitted a petition for declaratory order to FERC to find that the Federal Power Act ("FPA"), PURPA and FERC regulations do not preempt the Commission's decision to require California utilities to offer a certain price to CHP generating facilities of 20 MW or less that meet specific energy efficiency requirements.[8]

On May 11, 2010, the Joint Utilities together filed a separate petition at FERC for a declaratory order in which they argued that the Commission's decision is preempted by the FPA insofar as it sets rates for electric energy that is sold at wholesale.

On July 15, 2010, FERC issued *California Public Utilities Commission et al.* ("*FERC Declaratory Order*"), (2010) 132 FERC ¶ 61,047 which granted in part and denied in part the cross-petitions for declaratory order. In this order, FERC found:

> Although the CPUC has not argued that its AB 1613 program is an implementation of PURPA, we find that to the extent the CHP generators that can take part in the AB 1613 program obtain Qualifying Facility (QF) status, the CPUC's AB 1613 feed-in-tariff is *not* preempted by the FPA, PURPA or FERC regulations, subject to certain requirements.

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[8] *California Public Utilities Commission*, FERC Docket No. EL10-64.

(*Id.* at P 65 (emphasis in original).) To comply with PURPA, FERC found that the Commission's AB 1613 CHP program needed to meet two requirements: (1) the CHP generators must be QFs pursuant to PURPA; and (2) the rate established by the Commission should "not exceed the avoided cost of the purchasing utility." (*Id.* at P 67.)

On August 16, 2010, the Commission filed with FERC a request for clarification, or, in the alternative, a request for rehearing, which sought clarification regarding the avoided cost rates for facilities participating in the AB 1613 program.

On September 9, 2010, the Commission issued an amended scoping memo and ruling in the proceeding ("Amended Scoping Memo") asking for further comment on certain issues brought up in the Joint Utilities' PFM. Comments in response to the Amended Scoping Memo were filed by the Joint Utilities, DRA, FuelCell, CCDC, San Joaquin, and Sustainable Conservation. Joint comments were filed by Pacific Corp and Sierra Pacific Power Corporation.

On October 21, 2010, FERC issued an order, which granted the Commission's August 16, 2010 request for clarification. (*California Public Utilities Commission* ("*FERC Clarification Order*") (2010) 133 FERC ¶ 61,059.) In this order, FERC clarified that the state has a wide degree of latitude in setting avoided cost, can utilize a multi-tiered avoided cost rate structure, and that this approach is consistent with the avoided cost requirements set forth in Section 210 of PURPA. (*Id.* at PP 24 & 30.) FERC also clarified that state procurement obligations can be considered when calculating avoided cost, and it specifically overruled its prior holding from *SoCal Edison* to the extent its current determination was inconsistent with that clarification. (*Id.* at PP 29-30 *referring to SoCal Edison* (1995) 71 FERC ¶ 61,269 at 62,080.)

With this FERC guidance, the Commission issued D.10-12-055 on December 16, 2010. Decision 10-12-055 granted in part and denied in part the Joint Utilities' PFM. Most significantly, D.10-12-055 stated that it was modifying D.09-12-042 to be consistent with the *FERC Declaratory Order* and the *FERC Clarification*

Order by acknowledging that the AB 1613 program was being implemented pursuant to PURPA, that all generators in the program must be QFs, and that the prices set were consistent with avoided cost principles. D.10-12-055 modified D.09-12-042 so that the price paid to AB 1613 generators would be calculated each year based on the most current market price referent (MPR) inputs. (D.10-12-055 at pp. 9-10.) D.10-12-055 also modified the standard contracts approved in D.09-12-042 to correct errors and to resolve ambiguities. (D.10-12-055 at pp. 13-14.) Finally, D.10-12-055 clarified that GHG compliance costs were not reflected in the adopted MPR-based pricing formula and are instead addressed in the contracts as a direct pass-through of actual compliance costs from the generator to the utility, similar to treatment of renewable energy credits ("RECs"). (D.10-12-055 at p. 14.) Significantly, with the exception of the specific changes ordered to the AB 1613 contracts, D.10-12-055 did not order any specific language changes to D.09-12-042.

Before issuance of D.10-12-055, on November 22, 2010, the Joint Utilities filed at FERC a request for rehearing, or, in the alternative, reconsideration, partial vacatur, or clarification of the *FERC Clarification Order*. FERC denied rehearing of its *Clarification Order* on January 20, 2011. (*California Public Utilities Commission* ("*FERC Rehearing Order*") (2011) 134 FERC ¶ 61,044.) Among other things, it deferred to the Commission to implement FERC's guidance before it would rule on the Joint Utilities' assertions that the Commission has violated PURPA. (*Id.* at P 35.)

On January 6, 2011, the Joint Utilities filed a motion to stay D.10-12-055. DRA and San Joaquin filed a response, and CCDG and FuelCell filed a joint response to this motion to stay on January 10, 2011. On January 12, the motion to stay was denied by an Assigned Commissioner's ruling on the basis that it was premature because the Joint Utilities had not yet filed their rehearing application of D.10-12-055.

As described above, the Joint Utilities timely filed their applications for rehearing of D.10-12-055. PG&E and SDG&E filed a joint rehearing application and SCE filed its own rehearing application. At the same time, the Joint Utilities filed another motion for stay of D.10-12-055. San Joaquin filed a response and CCDG and

FuelCell filed a joint response to both rehearing applications and the Joint Utilities' stay motion. The Joint Utilities filed a reply to the responses to the motion for stay.

On January 31, 2011, notwithstanding the *FERC Rehearing Order* that declined to rule on the Commission's implementation of the FERC guidance until implementation was complete (*Rehearing Order*, *supra*, 134 FERC ¶ 61,044 at P 35), the Joint Utilities filed their Enforcement Petition with FERC. In essence, the Joint Utilities claim that the Commission's AB 1613 decisions violate either the FPA's requirement that rates must be just and reasonable, or violate PURPA by setting rates above the utilities' avoided costs.

The Joint Utilities also filed their supplemental advice letters with the Commission on January 31, 2011, in compliance with Ordering Paragraphs 9, 10, and 11 in D.10-12-055. Energy Division issued a notice of suspension on February 18, 2011, which stayed Energy Division's action on those supplemental advice letters for up to 120 days for further staff review.

On February 22, 2011, the Commission filed at FERC a Notice of Intervention, Motion to Dismiss, and Protest to the Joint Utilities' Petition for Enforcement. On March 31, 2011, FERC issued its "Notice of Intent Not to Act," declining to initiate an enforcement action against the Commission.

III. DISCUSSION

A. Rehearing On The Issue Of Whether The MPR-Based Price Formula Is A Lawful Measure Of "Avoided Cost" Under PURPA Is Denied

The Joint Utilities allege that the AB 1613 price formula violates PURPA because it will exceed their avoided costs. Specifically, PG&E/SDG&E argue that the AB 1613 price formula exceeds avoided cost because it pays a firm price for an as-available product. (PG&E/SDG&E's Rehrg App., at p. 2.) SCE claims the price formula exceeds avoided costs because it is higher than other avoided costs paid to other QFs with "identical relevant characteristics." (SCE's Rehrg. App., at p. 2.) In addition, the Joint

Utilities raise several other related arguments discussed in more detail in Section III.A.3 below. The Commission denied these claims for the reasons explained below.

1. There Is No Merit To PG&E/SDG&E's Argument That The AB 1613 Price Formula Exceeds Avoided Cost Because It Pays A Firm Price For An As-Available Product

PG&E/SDG&E argue that the AB 1613 price formula exceeds avoided cost because it pays a firm price for an as-available product. (PG&E/SDG&E's Rehrg App., at p. 2.) The Joint Utilities raised this same issue in their application for rehearing of D.09-12-042, framed primarily as a state law claim that the firm price violated the ratepayer indifference requirement of AB 1613. (Joint Utilities' Rehrg. App., filed January 20, 2010, at p. 13.) In the order denying that rehearing application, D.10-04-055, we rejected the argument that pricing for the AB 1613 program must be based on an as-available power price because AB 1613 CHPs operate as firm resources. (D.10-04-055 at pp. 9-11.) Thus, this argument is an impermissible collateral attack of a prior Commission decision. (See Pub. Util. Code, § 1709; see also, *People v. Western Air Lines, Inc.* (1954) 42 Cal.2d 621, 630.)

Notwithstanding the fact that this argument is a collateral attack, we address this issue again here and will modify D.10-12-055 to clarify our position on this issue. In summary, paying AB 1613 generators an "all in" price for as-available energy that is calculated based on the long term costs of constructing and operating a proxy baseload resource is appropriate and does not exceed the utilities' avoided costs because AB 1613 CHPs operate as firm resources and avoid capacity procurement for the utilities.

a) AB 1613 Requires Eligible CHPs To Operate As Firm Resources And Allows Procuring Utilities To Avoid Resource Adequacy Obligations

AB 1613 CHPs are required by statute to operate as firm resources. Public Utilities Code sections 2843(a)(2) and (3) require that an eligible CHP system must "be sized to meet the eligible customer-generator's thermal load," and must "operate

continuously in a manner that meets the expected thermal load and optimizes the efficient use of waste heat." Consistent with this obligation, section 2841(f) provides that the utilities are entitled to count the firm resource towards their resource adequacy obligations. These obligations are reflected in Sections 1.02 and 3.02 of the *pro forma* contracts approved in D.09-12-042, which require the generator to commit to an expected amount of energy production per term year and to pledge its generating capacity to the purchasing utility to use in meeting its resource adequacy obligations. Significantly, when a utility contracts with an AB 1613 CHP, it avoids a resource adequacy procurement obligation equivalent to the *full capacity* of the AB 1613 CHP (in other words, all of the power generated by the CHP), but the CHP is not paid for the full value of this avoided cost. Instead, the generator only receives a payment for the excess energy it sells to the utility. Thus, this payment clearly does not exceed the utility's avoided CCGT procurement costs.

b) FERC Rulings Recognize A State's Ability To Compensate QFs For Their Capacity Value

The Joint Utilities' continued attempts to challenge the firm/as available decision made by this Commission are troubling given the support for the Commission's actions. FERC expressly affirmed a state's ability to "determine that capacity is being avoided, and so … rely on the cost of such avoided capacity to determine the avoided cost rate" – which is exactly what the Commission is doing here. (*FERC Clarification Order*, *supra*, at P 26.) FERC went on to state:

> Further, in determining the avoided cost rate, just as a state may take into account the cost of the next marginal unit of generation, so as well the state may take into account obligations imposed by the state that, for example, utilities purchase energy from particular sources of energy or for a long duration.

(*Id.*) Here, consistent with AB 1613 requirements, the Commission has determined that an AB 1613 CHP will avoid capacity costs that the utility would otherwise incur, and quantifies those costs based on the marginal CCGT.

Reliance on a CCGT as the marginal unit is reasonable because, as we determined in all of the CHP decisions, it is much more likely that the Joint Utilities would seek to meet the baseload needs served by AB 1613 CHPs through a long term contract with a new, highly efficient CCGT. Among other things, the Commission's emission performance standards adopted in D.07-01-039 would likely compel such an outcome. That decision prohibits the utilities from entering into contracts of five years or longer with facilities that emit in excess of 1100 lbs/MWh of carbon dioxide equivalent. In effect, this means that the utilities are limited to procuring long term commitments[9] for sales of electricity from CCGTs, renewables, other non-carbon emitting resources such as hydroelectric power, and CHPs. (See, e.g., D.07-01-039 at Findings of Fact 2, 3, and 4.)[10]

A payment for capacity value based on avoided procurement is not new policy. FERC addressed this very issue when it adopted Order 69 implementing Section 210 of PURPA in 1980. In response to claims that avoided cost should not include capacity payments, FERC explained that purchases of power from QFs "will fall somewhere on the continuum between" firm and non-firm service or capacity and energy. For facilities that demonstrate "a degree of reliability that would permit the utility to defer or avoid construction of a generating unit or the purchase of firm power from another utility, then the rate for such a purchase should be based on the avoidance of both energy and capacity costs."[11] As AB 1613 CHPs must, pursuant to statute, provide this

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[9] For GHG emissions purposes, Public Utilities Code section 8340(f) defines a "Long-term financial commitment" to mean a new or renewed contract for a term of five years of more. (Pub. Util. Code, § 8340, subd. (f).) Pub. Util. Code § 8341(a) prohibits the utilities from entering into contracts of 5 years or more for baseload generation that does not comply with the Commission's GHG emission performance standards. (Pub. Util. Code, § 8341, subd. (a).)

[10] While an AB 1613 CHP may contract for a term of one to ten years, we anticipate most AB 1613 CHPs to contract for ten years for financing purposes.

[11] Order No. 69, FERC Stats. & Regs., Regs. Preambles, 1977-1981, ¶ 30, 128 at 30,882 (1980).

degree of reliability and allow the utility to avoid local resource adequacy procurement, they provide both energy and capacity and are properly compensated for both.

For all of these reasons, the Joint Utilities' continued challenges to the firm/as-available decision made by the Commission in this proceeding are without merit and rehearing on this issue is denied.

2. There Is No Merit To SCE's Argument That The AB 1613 MPR-Based Price Is Not An Avoided Cost Because It Exceeds The Price Paid To Other QFs

In its rehearing application, SCE contends that the AB 1613 MPR-based price formula exceeds avoided costs because it is higher than other avoided costs paid to other QFs with "identical relevant characteristics." (SCE's Rehrg. App., at pp. 2, 13-17.) SCE claims that the Commission must reconcile its planned implementation of the AB 1613 CHP program with the short run avoided cost ("SRAC") adopted in D.07-09-040 and D.08-07-048 and the avoided cost price agreed to in the QF Settlement adopted in D.10-12-035. (SCE's Rehrg. App., at p. 5.)

To support its claim that these prices are lower than the MPR-based price formula, SCE provides an "illustrative" table comparing its projected AB 1613 price to its projections of other QF pricing formulas, including the "Option A" avoided cost price provided in the QF Settlement. (SCE's Rehrg. App., at p. 15.) SCE complains that the Commission has failed to explain "why it is appropriate for a CHP QF that begins operations after January 1, 2008 to receive a higher 'avoided cost' price than an identical CHP QF that begins operations on an earlier date" and why "it is appropriate to mandate a higher price for AB 1613 CHP QFs, as the efficiency and on-line date are the only two distinguishing factors between AB 1613 CHP QFs and other CHP QFs." (SCE's Rehrg. App., at p. 6 and p. 16.) Citing *Independent Energy Producers Association v. CPUC* (9th Cir. 1994) 36 F.3d 848, 854-855, SCE argues that "[i]t would be unlawful for the Commission to distinguish avoided cost pricing on the basis of efficiency…" (SCE's Rehrg. App., at p. 16, fn. 45.)

SCE's contention that the Commission is obligated to set the same rate for AB 1613 CHPs as older, less-efficient CHPs operating under the QF Settlement or some other arrangement, has no merit.

As an initial matter, SCE made the same argument and presented an identical price comparison chart in its joint comments with PG&E on the proposed decision disposing of the Joint Utilities' PFM. (SCE/PG&E Comments filed December 6, 2010, at p. 8).[12] In addressing the argument at that time, D.10-12-055 recognized that the short run avoided cost calculations provided from the QF Settlement were "outside the record of the proceeding, and should therefore be disregarded." (D.10-12-055 at pp. 18-19 and fn. 14.) SCE's identical "Table 1 Illustrative Levelized Price Comparison" provided on page 15 of its rehearing application is similarly "outside the record of the proceeding, and should therefore be disregarded."[13]

Notwithstanding this procedural infirmity, D.10-12-055 addressed the merits of SCE's claims, raised again here, that different avoided costs are not allowed under PURPA. The discussion in D.10-12-055 relied heavily on the *FERC Clarification Order*, which expressly addressed, and rejected, SCE's current argument:

> [T]he FERC Clarification Order supports a wide degree of latitude for the Commission to establish a utility's avoided cost; found that the concept of a multi-tiered avoided cost rate structure is consistent with the avoided cost requirements set forth in Section 210 of PURPA and FERC regulation; and recognizes that full avoided cost need not be the lowest possible avoided cost and can properly take into account real

[12] A similar chart, comparing SRAC to the AB 1613 prices calculated by the Joint Utilities, was also provided on page 16 of the Joint Utilities rehearing application for D.09-12-042, filed on January 20, 2010.

[13] The record stands submitted prior to issuance of a proposed decision. (*See, e.g.,* Commission Rules of Practice and Procedure, Rules 13.14(a) and 14.2(a).) The Commission has routinely held that evidence outside the record will not be considered in disposing of an application for rehearing. (*See, e.g.*, D.06-06-070 at fn. 5: "This evidence, which occurred after the issuance of the Decision, is outside the record and its attempted introduction in an application for rehearing is improper. It is accordingly not considered in disposing of this application for rehearing.")

> limitations on alternate sources of energy imposed by state law.
>
> The significance of the FERC's Clarification Order is that in contrast to its *Southern California Edison Company* decisions in the 1990s, where FERC required states to consider purchases from "all sources," including coal-fired generation, in setting avoided costs, the FERC's Clarification Order rules that all sources can be limited to those that are available to the utilities under state law.

(D.10-12-055 at p. 28, relying on *FERC Clarification Order*, *supra*, 133 FERC ¶ 61,059 at PP 26-30 (footnotes omitted).)

Although D.10-12-055 addressed SCE's claims, it did not order specific modifications to D.09-12-042. To ensure that the Commission's position on this issue is clear, and for the convenience of the parties, we order a number of additional modifications to D.10-12-055 (modifying D.09-12-042), based on the discussion below, to further clarify our positions on this issue.

a) The Pricing Terms Established By The QF Settlement Do Not Apply To The AB 1613 Program

SCE's constant refrain that the Commission must harmonize the AB 1613 CHP price with the QF Settlement – or that it cannot adopt an avoided cost that is more than the QF Settlement price - has no basis in either the record of this proceeding or the QF Settlement decision. The QF Settlement decision, D.10-12-035, expressly declined to apply the QF Settlement price to AB 1613 CHPs:

> The Proposed Settlement is comprehensive, but it does not resolve issues in numerous Commission proceedings implementing recent statutory requirements that pertain to QFs of 20 MW or less, such as new CHP systems under Assembly Bill 1613 (codified as Pub. Util. Code sections 2840-2845), except to acknowledge that the megawatt (MW) and GHG reductions will count toward the investor-owned utilities' MW and GHG reduction targets.

(*See* D.10-12-035 at p. 2.) Consequently, SCE's claim that the Commission must harmonize the AB 1613 program with the QF Settlement has no merit.

b) The AB 1613 Program Does Not Unduly Discriminate Against Non-AB 1613 CHPs

To the extent SCE insists that the MPR-based AB 1613 CHP price formula is "discriminatory" under the FPA as compared to the QF Settlement price, SCE overstates its case. (SCE's Rehrg. App., at pp. 13-16). The legal standard applied by FERC is *undue* discrimination. Thus, when contract clauses differentiate among energy sellers, FERC looks to whether there is a reasonable basis for such different treatment. In *ISO New England*, FERC upheld ISO New England's right to provide grandfathered contracts one type of oversupply clause, and new contracts another type of oversupply clause. FERC stated: "What is prohibited by the Federal Power Act is undue discrimination, not all differences in treatment no matter the justification." (*ISO New England* (2008) 122 FERC ¶61,016 at P 29.)

FERC has routinely engaged in differentiation among generators in its implementation of PURPA. In the preamble discussion to FERC Order 69 implementing PURPA, FERC found that it was appropriate to apply a potentially lower form of pricing to facilities in existence prior to the adoption of PURPA that might have qualified as QFs, and a higher "full avoided cost" to those that commenced construction on or after the date of PURPA's enactment. (Order No. 69, FERC Stats. & Regs., Regs. Preambles, 1977-1981, ¶ 30,128 at 30,882 (1980).) FERC reasoned that the distinction was "intended to reflect the need for further incentives and the reasonable expectations of persons investing in cogeneration or small power production facilities prior to or subsequent to the enactment of this law." (*Id.*) Thus, FERC itself acknowledged that differing treatment among units with "identical relevant characteristics," including development "incentives," were appropriate in the context of an avoided cost.

Similarly, FERC has recognized that QFs 20 MW or below represent a special class of "small QFs" which has routinely been subjected to different standards than "large QFs" (those above 20 MW) in various FERC regulations. Samples of this

treatment include FERC's "rebuttable presumption" that a QF 20 MW or smaller does not have nondiscriminatory access to energy markets;[14] FERC's continued exemption of QFs 20 MW or smaller from Sections 205 and 206 of the FPA;[15] and FERC's determination that QFs 20 MW or smaller operate under different interconnection rules than large generators.[16]

Given FERC's own precedent, it can hardly be considered undue discrimination if a short run avoided cost payment is paid to existing CHPs, and another type of avoided cost payment is paid to encourage new AB 1613 CHPs that will operate under a different statutory and contractual framework – one that imposes higher efficiency standards and provides resource adequacy benefits to the utilities. Both payments comply with avoided cost principles.

With regard to SCE's implication that older CHPs are unfairly discriminated against because they will be paid the SRAC agreed upon in the QF Settlement, the Fifth Circuit Court of Appeals has recognized that to the extent parties agree to something in a settlement, it is not undue discrimination to hold parties to their bargain. (*Public Service Co. v. FERC* (5th Cir. 1988) 851 F.2d 1548, 1557.) Similarly, the U.S. Supreme Court has recognized that, consistent with FERC regulations, a QF and a utility "may negotiate a contract setting a price that is lower than a full avoided cost rate." (*American Paper Institute v. American Electric Power Service Corp.* (1982) 461 U.S. 402, 416; *see also* 18 C.F.R. § 292.301(b)(1).) It therefore follows that paying older CHPs one price and newer CHPs another price does not necessarily constitute undue discrimination.

[14] *See, e.g.,* Order No. 688-A, 72 Fed. Reg. 35872 (June 29, 2007) at PP 94-100.

[15] *See, e.g.,* Order No. 671, 71 Fed. Reg. 7852 (February 15, 2006) at P 99.

[16] *See, e.g.,* Order No. 688, 71 Fed. Reg. 64342 (November 1, 2006) at P 76.

c) A PURPA Contract May Include Sanctions For Non-Compliance With State Efficiency Requirements

In D.10-12-055 the Commission explained its two tier pricing structure. AB 1613 CHPs are to receive the MPR-based price so long as they comply with AB 1613. Should they fail to comply with AB 1613, but retain their QF status, they will receive payments pursuant to the most current SRAC. SCE claims that pursuant to the Ninth Circuit decision in *Independent Energy Producers* "[i]t would be unlawful for the Commission to distinguish avoided cost pricing on the basis of efficiency…" (SCE's Rehrg. App., at p. 16, fn 45.) We disagree. So long as the two prices in the two tier pricing structure do not exceed the utilities' avoided cost, and payment is based on contract compliance, SCE's claim has no merit.[17]

The state may require higher efficiency from CHPs, and pay a lower avoided cost for failure to meet these requirements; such a program advances both state and federal goals to encourage efficient CHPs. Both PURPA and the Energy Policy Act of 2005 ("EPAct 2005"), like AB 1613, recognize CHPs as a special class of highly efficient facilities, with EPAct 2005 expressly directing FERC to consider revising its CHP criteria to ensure "continuing progress in the development of *efficient* electric energy generating technology." (See, e.g., 18 C.F.R. § 292.205 and 16 U.S.C. §824a-3(n)(1)(A)(iii) (emphasis added); see also Conf. Rep. No. 95-1750, pp. 97-98 (1978).) Several courts have also acknowledged, with approval, the efficiency benefits of CHPs. In particular, the U.S. Supreme Court upheld FERC's decision to pay "full avoided costs" to CHPs and other small power producers as a development incentive to encourage fuel efficiency:

> … it was not unreasonable for the Commission to prescribe the maximum rate authorized by PURPA. The Commission's order makes clear that the Commission considered the

[17] The *FERC Clarification Order* also addressed the two tier pricing structure, and those holdings are described in more detail in Section III.A.3.c) below.

> relevant factors and deemed it most important at this time to provide the maximum incentive for the development of cogeneration and small power production, in light of the Commission's judgment that the entire country will ultimately benefit from the increased development of these technologies and the resulting decrease in the Nation's dependence on fossil fuels. …The basic purpose of § 210 of PURPA was to increase the utilization of cogeneration and small power production facilities and to reduce reliance on fossil fuels.

(*American Paper Inst. v. American Elec. Power* ("*American Paper*") (1983) 461 U.S. 402, 417-418.) The Supreme Court in *American Paper* also recognized that "a qualifying facility and a utility may negotiate a contract setting a price that is lower than a full-avoided cost rate." (*Id.* at 416.)

Given the holdings of *American Paper*, SCE's reference to *Independent Energy Producers* as a barrier to the AB 1613 CHP two-tier payment structure is both inaccurate and inapposite here. *American Paper* clearly supports the two-tier payment structure we adopt here, and the holdings of *Independent Energy Producers* are irrelevant to the issue. *Independent Energy Producers* focused on QF status determinations, and whether a state could delegate QF status determinations to the utilities. It determined that only FERC could make a QF status determination, and thus the delegation was improper. In that context, the Court noted that a state could not sanction a QF for failure to meet *federal* QF efficiency standards. The QF status issues addressed by *Independent Energy Producers* are not at issue here; compliance with *state* law requirements is at issue. To the extent that a QF does not comply with *state* efficiency standards, that is up to the state to police and this is properly done through contracting requirements that provide sanctions for failure to comply.

We recognize that, consistent with *Independent Energy Producers,* we may not revoke a facility's QF status, delegate that authority to a utility, or reduce the price paid to below avoided cost, and we do not attempt to do so here. To the extent that the price adjustment terms for failure to meet state efficiency requirements are reflected in the AB 1613 contract, and that both the high and low prices are avoided costs, it is a valid

provision that meets both state and federal efficiency goals and the holdings in *Independent Energy Producers* do not preclude us from establishing such a structure.

d) There Are Legitimate Distinctions Between Short Run and Long Run Avoided Costs

There is an appropriate difference between the short run avoided cost paid to the QF Settlement CHPs – which is "short run" compensation paid based on the time of delivery for as-available energy, and the "long run" or "full avoided cost" compensation envisioned by the AB 1613 CHP program. SCE dismisses this distinction as "without merit." (SCE's Rehrg App., at p. 17.) However, both FERC and the U.S. Supreme Court have recognized the "merit" to such a distinction. (Order No. 69, FERC Stats. & Regs., Regs. Preambles, 1977-1981, ¶ 30, 128 at 30,882 (discussed in Section III.A.2.b), *supra*); *American Paper, supra*, at 412-418 (upholding requirement that QFs receive full avoided costs rate).)

Further, SCE's own arguments support the Commission's point here. SCE explains that historically only firm capacity QFs have been allowed longer term contracts, in part because they allow the utilities to "more precisely avoid the procurement of additional capacity." (SCE's Rehrg App., at p. 17, *citing* D.07-09-040 at p. 92 (slip op.).) Because eligible AB 1613 CHPs will, by statute, operate as firm resources and permit the utilities to avoid procurement of resource adequacy capacity, it is appropriate for AB 1613 CHPs to be compensated as long term resources. This logic supports the Commission's determination in D.10-12-055 to pay SRAC only as a second tier payment to those CHPs operating as QFs, but not in compliance with AB 1613 eligibility requirements. (D.10-12-055 at pp. 29-32). Where a CHP operates as a firm resource and meets the higher efficiency and emission standards of AB 1613, it is entitled to a long run avoided cost payment. Where it fails to meet these requirements, but operates as any other CHP QF, it is entitled to the same SRAC payment as those other units.

3. There Is No Merit To The Joint Utilities' Remaining Arguments, That The MPR-Based Price Does Not Constitute An Avoided Cost

In their rehearing applications, in addition to the specific arguments regarding the MPR-based price discussed in Sections III.A.1 and III.A.2 above, the Joint Utilities offer a series of overlapping arguments. They assert that: (1) the MPR-based price was adopted prior to the Commission's recognition that the AB 1613 program needed to comply with PURPA and its avoided cost requirements, and as a result, the record is insufficient to establish that a CCGT is a reasonable proxy for the unit avoided by an AB 1613 CHP (PG&E/SDG&E's Rehrg. App., at pp. 5-7; SCE's Rehrg. App., at pp. 2-3, 7-9, and 13); (2) the MPR-based price was not established in accordance with the criteria for avoided cost set forth in FERC regulations at 18 C.F.R. § 292.304 (PG&E/SDG&E's Rehrg. App., at pp. 5-6; SCE's Rehrg. App., at p. 9); and (3) use of a CCGT as the avoided cost proxy does not meet FERC's conditions for a resource-specific avoided cost (PG&E/SDG&E's Rehrg. App., at p.10; SCE's Rehrg. App., at p. 7).

For many of the reasons already discussed in Sections III.A.1 and III.A.2 above, these arguments are without merit. Notwithstanding the fact that D.09-12-042 was originally adopted outside of the PURPA regime and did not characterize its adopted AB 1613 price as an "avoided cost," the Commission sought, in that decision, to set the energy prices paid to the AB 1613 generators at the utilities' avoided costs in order to meet the AB 1613 requirement of ratepayer indifference. (See Pub. Util. Code, § 2841(b)(4).) As the Final Staff Proposal explained:

> The MPR is based on the costs of a proxy power plant (gas-fired combined-cycle plant) that would be necessary if not for some other form of new generation, in this case CHP. Basing the price paid for excess electricity from a CHP facility on the estimated cost of a marginal generating unit, meets the

ratepayer indifference requirement of PUC Section 2841(b)(4).[18]

FERC regulations define "avoided costs" as: "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." (18 C.F.R. § 292.101(b)(6).) Consistent with the Final Staff Proposal, D.09-12-042 found that a CCGT represents a reasonable proxy for the generation that a utility would have to procure if not for a CHP facility participating in the AB 1613 program. (D.09-12-042 at p. 35.) This is the essence of avoided cost.

For clarity, and at the risk of redundancy, we address each of the Joint Utilities' specific arguments below.

a) The Record Reflects That The MPR-Based Price Is An Avoided Cost

The Joint Utilities assert that the record is insufficient to establish that a CCGT is a reasonable proxy for the unit avoided by an AB 1613 CHP because the MPR-based price was adopted prior to the Commission's recognition that the AB 1613 program needed to comply with PURPA and its avoided cost requirements. (PG&E/SDG&E's Rehrg. App., at pp. 5-7; SCE's Rehrg. App., at pp. 2-3, 7-9, and 13.)

As discussed above, the Joint Utilities are correct that the MPR-based price was adopted at a time when the Commission took the position that the AB 1613 CHP program was not subject to PURPA. However, this point is irrelevant. The legitimate question is not when the AB 1613 price was adopted, or under what circumstances, but whether or not the record demonstrates that the AB 1613 price is an appropriate avoided cost. As discussed above, notwithstanding its belief that the AB 1613 program did not need to be implemented pursuant to PURPA, the Commission confined itself to an MPR-

[18] The Final Staff Proposal was Attachment A to the "Administrative Law Judge's Ruling Incorporating Energy Division Final Staff Proposal Into the Record and Providing for Comments Thereon," filed August 4, 2009 ("Final Staff Proposal").

based price in order to comply with AB 1613's ratepayer indifference standards. As the Joint Utilities argued in their first rehearing application:

> By definition, "avoided cost" should be the measure of ratepayer indifference. That is, if ratepayers are simply paying the price they would have otherwise paid "but for" the AB 1613 purchase, they are indifferent to the existence of the AB 1613 tariff.

(Joint Utilities' Rehrg. App. Filed January 20, 2010, at pp. 12-13.) We agree with the Joint Utilities. In D.09-12-042 we found that the MPR-based price, as a reasonable proxy for the generation the utilities would have purchased "but for" the AB 1613 purchase requirements, met the ratepayer indifference standard of AB 1613. By the Joint Utilities' own definition, it is also a finding of avoided cost.

To elaborate on the background supporting our decision on this matter, which is not reflected in the text of our prior CHP decisions, the MPR is intended to represent the long term market price of electricity for fixed price contracts. (Pub. Util. Code, § 399.15, subd. (c)(1).) The MPR is derived from the construction, operating and maintenance costs associated with a highly efficient 500 MW CCGT. The MPR inputs and methodology were developed pursuant to Public Utilities Code section 399.15(c) through a public process and the Commission relies on a public process to periodically update the MPR inputs and methodology.[19]

Based on this history of the MPR, and the fact that many of the pricing components of the MPR correspond to AB 1613's pricing requirements,[20] the Commission found in D.09-12-042 and affirmed in D.10-04-055 that the MPR's CCGT is the unit most likely to be procured by the utilities in the absence of the AB 1613 procurement obligation. (D.09-12-042 at p. 35 (slip op.); D.10-04-055 at pp. 8-9 (slip op.).) In those decisions, the Commission relied upon a statement in the record made by

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[19] *See, e.g.*, D.05-12-042; D.07-09-024; D.08-10-026; and the Commission's MPR website at http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr

SDG&E/SoCal Gas that the "export profile [of a small CHP facility] is closest to that of a CCGT." (*Id.*, citing to SDG&E/SoCal Gas Comments filed August 24, 2009, at p. 3.) PG&E/SDG&E now seek to distance themselves from that assertion by claiming that it has been taken out of context. In their rehearing application they point out that the discussion which follows the statement went on to distinguish an AB 1613 CHP from a CCGT:

> However, the characteristics of small CHP (less than 20 MW) do not match precisely those of a CCGT in that a CCGT is able to provide firm capacity and ancillary services. SDG&E and SoCalGas' key reservation with regard to whether [the MPR-based price] meets the test of ratepayer indifference is whether paying a firm price for as-available capacity is consistent with ratepayer indifference.

(PG&E/SDG&E's Rehrg. App., at pp. 6-7.) In this manner, PG&E/SDG&E simply retread their argument, rejected in Section III.A.1, and in both D.09-12-042 and D.10-04-055, that an AB 1613 CHP is not a firm resource and should not be paid as a firm resource.

Because the Commission has found that a price based on the MPR's CCGT unit most closely approximates the costs avoided by procuring energy from AB 1613 CHPs, and the utilities have failed to present a reasonable argument that this is not the case, we find that the MPR-based price will not exceed the utilities' avoided costs and that the Joint Utilities' claim is without merit.

b) The AB 1613 Price Addresses Many of The Factors Set Forth in FERC's Regulations

The Joint Utilities argue that the MPR-based price was not established in accordance with the criteria for avoided cost set forth in FERC regulations at 18 C.F.R. § 292.304 (PG&E/SDG&E's Rehrg. App., at pp. 5-6; SCE's Rehrg. App., at p. 9). It is

(footnote continued from previous page)
[20] See Final Staff Proposal at 10.

true that the Commission did not consult FERC's regulations when developing the MPR-based price; however, the AB 1613 price is consistent with those regulations, and that is all that is required. The *FERC Clarification Order* reiterated:

> As the Commission has previously explained, "states are allowed a wide degree of latitude in establishing an implementation plan for section 210 of PURPA, *as long as such plans are consistent with our regulations*. Similarly, with regard to review and enforcement of avoided cost determinations under such implementation plans, we have said that our role is generally limited to ensuring that the plans are *consistent with section 210 of PURPA*…."

(*FERC Clarification Order*, *supra*, at P 24 (emphases added), with the following cases cited in the footnote: *American REF-FUEL Company of Hempstead* (1989) 47 FERC ¶ 61,161, at 61,533; *Signal Shasta* (1987), 41 FERC ¶ 61,120 at 61,295; *see also LG&E Westmoreland Hopewell* (1993) 62 FERC ¶ 61,098, at 61,712.)

FERC's regulations regarding the setting of avoided cost rates are set forth at 18 C.F.R. § 292.304. Subsection (e) of those regulations sets forth the factors that a state shall "to the extent practicable" take into account when determining an avoided cost. As reflected in the *FERC Clarification Order*, these factors are considered "guidance"; they are not mandatory requirements.[21] Notably, the Commission's MPR-based price takes many of these factors into account including, among other things, time of delivery factors, the expected reliability of the QF, contractual terms, sanctions for non-compliance (all set forth at § 292.304(e)(2)), and the ability of the AB 1613 CHP to allow the utility to defer capital additions and reduce fossil fuel use (§ 292.304(e)(3)).

[21] See, also *Plymouth Rock Energy Associates v. Dept. of Pub. Utils.*, (1995) 648 N.E.2d 752, 754 ("Although FERC's regulations provide guidelines for the calculation of avoided costs, 18 C.F.R. § 292.304 (e), FERC has granted the States flexibility in implementing rates for purchase and, specifically, determining avoided costs."); *Cogen Lyondell, Inc*. (2001)95 F.E.R.C. ¶ 61,243 at P 61,838 ("The Commission implemented section 210(b) of PURPA by promulgating 18 C.F.R. § 292.304 (2000), which states that rates for purchases from QFs shall satisfy the requirements of section 210(b) of PURPA if the rate equals "avoided costs" and which sets forth guidance on how a state regulatory authority or nonregulated electric utility shall determine avoided costs."); similar at *City of Ketchikan, Alaska*, (2001)

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Consequently, the Commission's AB 1613 price is consistent with FERC regulations and the Joint Utilities' arguments on this issue have no merit.

c) The AB 1613 Price Complies With FERC's Guidance On Multi-Tier Avoided Costs

The Joint Utilities argue that use of a CCGT as the avoided cost proxy unit does not meet FERC's conditions for a resource-specific avoided cost. (PG&E/SDG&E's Rehrg. App., at p.10; SCE's Rehrg. App., at p. 7). SCE points out that "there is no percentage or quantity procurement requirement in the AB 1613 statute" or the Commission's decisions implementing the statute. (SCE's Rehrg. App., at p. 7.) "As such, there is no basis to create a separate avoided cost for AB 1613 CHP pursuant to the Clarification Order." (*Id.*)

The Joint Utilities' argument is flawed. The Commission does not attempt to adopt a "resource-specific" avoided cost here. Rather, it establishes a two-tiered avoided cost, with the top of the tier – a long run avoided cost - defined by a CCGT avoided unit, and the bottom of the tier – a short run avoided cost - defined by the current SRAC.

The *FERC Clarification Order's* discussion of a "resource specific cost" is only relevant here to the extent that FERC clarified that an avoided cost determination need not to consider "all sources" of energy, but only those sources "able to sell to the utility." Nothing in the *FERC Clarification Order* suggests that the two-tier structure may only be implemented under a "resource specific" program where the state specifies a percentage of procurement from the specific resource. Rather, FERC was clear that the Commission need only comply with section 210 of PURPA and its existing regulations, and such a two-tier rate structure would be acceptable.

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94 F.E.R.C. ¶ 61,293 at P 62,061.

The Commission's intended two-tier rate structure was clearly presented to FERC. The Commission requested clarification from FERC that it could implement a two tiered rate structure where AB 1613 CHPs receive full avoided cost rates based on their higher efficiency and non-AB 1613 CHPs receive SRAC rates. (See, e.g., *FERC Clarification Order* at PP 20-21.)

The *FERC Clarification Order* responded:

> [W]e find that the concept of a multi-tiered avoided cost rate structure can be consistent with the avoided cost rate requirements set forth in section 210 of PURPA and in the Commission's regulations.

(*FERC Clarification Order* at P 20; see also P 30.) FERC then outlined the relevant statutory and regulatory framework: (1) that Section 210(b) of PURPA requires that QF purchases be at rates that are just and reasonable, not discriminatory, and not in excess of avoided costs; (2) that pursuant to § 292.303 of FERC's regulations, utilities must purchase from QFs consistent with § 292.304; (3) that § 202.304 set forth the factors to be considered in determining avoided cost; and (4) that states are allowed a wide degree of latitude in determining avoided cost as long as their plans are consistent with section 210 of PURPA and FERC regulations. FERC then explained that that there was no record on which to rule whether the Commission's proposed rates would either satisfy or violate the avoided cost requirements of section 210 of PURPA or its regulations. (*FERC Clarification Order* at PP 22-25.) Thus, while FERC declined to explicitly determine whether the Commission's proposed rates were reasonable, it provided guidance that the Commission needed simply to comply with FERC's existing regulations on setting avoided costs. As described herein, the Commission has met this requirement. The Joint Utilities' arguments that the Commission is somehow obligated to comply with FERC's comments regarding a "resource-specific cost" are inapposite and without merit.

B. Rehearing On The 10% Location Bonus Is Denied

The AB 1613 program provides that an AB 1613 CHP located in a local resource adequacy area shall be paid a 10% location bonus calculated based on its total

energy payment. Both of the Joint Utilities' rehearing applications claim that this 10% location bonus violates PURPA because it is not based on the utilities' avoided costs of upgrades to the transmission and distribution ("T&D") system. (PG&E/SDG&E's Rehrg. App., at pp. 11-12; SCE's Rehrg. App., at pp.10-11.)

The Joint Utilities raised this same issue in their January 20, 2010 application for rehearing of D.09-12-042. The decision denying rehearing on this issue, D.10-04-055, explained that the basis for the payment was the value of deferred T&D upgrades, as well as the value of local grid stability and reliability:

> [D.09-12-042] determines that a 10% location bonus is appropriate in constrained areas because CHP sited in these areas would provide system benefits such as transmission and distribution upgrade deferrals and local grid stability and reliability. (D.10-04-055, at p. 10).

(D.10-04-055, at p. 10).

While D.10-04-055 cited to the record to generally support this conclusion, the Joint Utilities are correct it did not explain the avoided cost basis for the 10% location bonus. In other words, there was no showing of utility avoided costs that justified the 10% number. This is because the Commission at that time was not implementing the program pursuant to PURPA.. Rehearing on this issue is not warranted. However, given the intervening change, we modify D.10-12-055 (modifying D.09-12-042) so that the clarifying discussion provided below is added to D.09-12-042 to describe the record basis for the 10 % location bonus, how it is related to an "actual determination" of the utilities' avoided costs, and how it was applied in an extremely conservative manner that assures it will, in no event, exceed the utilities' avoided T&D costs.

1. Record On The 10% Location Bonus

At the initiation of this rulemaking, the California Cogeneration Council ("CCC") filed comments noting that the Commission currently uses a model to calculate average T&D avoided cost values for each utility's service area, by each utility division or planning region. (CCC Comments, filed July 31, 2008.) CCC provided, as Attachment A to its comments, a sample of the T&D avoided costs calculated for each

utility by the model ("CCC Attachment A"). The spreadsheet model is commonly referred to as the "E3 Model" in the parties' comments. To calculate T&D avoided costs, the E3 Model relies upon each utility's marginal T&D costs adopted in their general rate cases.

Based on the avoided cost numbers reflected in CCC Attachment A, CCC proposed to pay an avoided T&D cost "adder" to AB 1613 generators located in areas that would produce higher than average avoided cost benefits to ratepayers, but did not specifically identify the amount of the adder. (CCC Comments, filed July 31, 2008, at pp. 10-14 and Attachment A.) CCC proposed that the generators would cooperate with the utilities to identify the best areas to site such projects to generate the highest avoided costs. In making this proposal, CCC acknowledged that the utilities have traditionally argued against such a T&D avoided cost on the basis that such costs are "highly site-specific and that a case-by-case analysis is needed." (CCC Comments, filed July 31, 2008, at pp.12-13.) CCC noted that "to the CCC's knowledge, no CHP or renewable projects have ever been compensated for such locational benefits." (CCC Comments, filed July 31, 2008, at p. 13.)

In commenting on CCC's proposal to identify T&D avoided costs, all three utilities agreed that distributed generation facilities have the potential to avoid T&D costs; however, each one argued that this proceeding was not the forum for quantifying those costs. (See, e.g., SCE Comments, filed August 15, 2008, at p. 4.) Among other things, they argued, as CCC anticipated, that each DG facility must be considered separately, on a case-by-case basis, to calculate such avoided costs. (See, e.g., SCE Comments, filed August 15, 2008, at p. 4 .)[22] None of the utilities suggested that the E3 Model avoided cost calculations provided in the CCC Attachment A were inaccurate.

[22] SCE argued: "Because identifying a T&D price adder would require a case-by-case analysis of each participating system and physical assurance, and because AB 1613 contemplates a standard offer tariff with no distinction for location or physical assurance, the Commission should reject CCC's proposal for a T&D price adder." (SCE Comments, filed August 15, 2008, at p. 4; see also PG&E Comments, filed August 15, 2008, at pp. 7-8; and SDG&E/SoCal Gas Comments, filed August 15, 2008, at p. 2 (outlining

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On August 4, 2009, an Administrative Law Judge's ruling incorporated the Energy Division Final Staff Proposal into the record of the proceeding and requested party comments on the proposal.[23] The Final Staff Proposal suggested a 10% location bonus under both proposed pricing options for any eligible CHP located in a distribution or transmission constrained area. The Final Staff Proposal reasoned that CHP systems situated in constrained areas could provide system benefits such as transmission and distribution upgrade deferrals and local grid stability and reliability. The Final Staff Proposal asked parties to comment on how to determine location or distribution constrained areas for purposes of applying this bonus.

SCE and PG&E/TURN argued that the proposed location bonus of 10% was unsupported by analysis and unreasonable. (PG&E/TURN Comments, filed August 24, 2009, at p.13; SCE Comments, filed August 24, 2009, at p. 12.) They also asserted that the "locational marginal price" ("LMP") values in the California Independent System Operator Corporation ("CAISO") market are the only accurate reflection of actual congestion and losses on the grid. (PG&E/TURN Comments, filed August 24, 2009, at p.13; SCE Comments, filed August 24, 2009, at p. 14.) SCE also pointed out that adopting a generic location adder would be inconsistent with the generator-specific methodology adopted in D.03-02-068. (SCE Comments, filed August 24, 2009, at pp. 12-14.)

SDG&E/SoCalGas contended that if certain facilities received a bonus because of their favorable location, then facilities located in less than favorable locations should receive less. (SDG&E/SoCalGas Comments, filed August 24, 2009, at p. 6.) SDG&E/SoCalGas also contended that CHP located in its service territory is more valuable than CHP located elsewhere in the CAISO-controlled grid given the need for

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SDG&E's 4 criteria proposal for when a facility may qualify for T&D avoided costs, adopted in D.03-02-068).)

[23] See note 18, *supra*.

local resources in their service territory. They argued that locational value should only be provided to CHP located in areas with local resource adequacy requirements when contracting with the local utility. (SDG&E/SoCalGas Comments, filed August 24, 2009, at p. 6.)

CCDC and FuelCell supported the Final Staff Proposal's location bonus. CCDC and FuelCell suggested that the location bonus should be provided to any location where the CAISO nodal LMP exceeds the zonal price. (CCDC Comments, filed August 24, 2009, at 9; FuelCell Comments, filed August 24, 2009, at p. 9.)

2. Analysis of the 10% Location Bonus

Historically, the Commission has agreed with the utilities that while distributed generation facilities unquestionably generate avoided T&D costs, a facility-specific analysis was required before a T&D avoided cost could be paid to generators. The Commission has therefore previously declined to adopt a uniform avoided cost calculation for T&D. Instead, D.03-02-068, issued February, 2003, established four facility-specific criteria to be met for a facility to qualify for avoided T&D costs. To our knowledge, which is consistent with CCC's, no facility has ever qualified for T&D avoided costs under this test.

Notwithstanding the determinations in D.03-02-068, the Commission's position on this matter has evolved over the last eight years in other proceedings so that today the E3 Model is used to calculate avoided T&D costs to determine the cost effectiveness of the utilities' energy efficiency and demand response programs.[24] The utilities benefit from the inclusion of uniform avoided T&D costs in these programs. The more cost-effective the program, because of the addition of T&D avoided costs, the more money utility shareholders may receive in the form of performance incentives.

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[24] The E3 Model for calculating avoided costs for energy efficiency was adopted in D.05-04-024 and updated in 2008 to apply to the utilities' 2009-2011 energy efficiency portfolio plans. (Assigned Commissioner's and Administrative Law Judge's Ruling, R. 06-04-010, April 21, 2008.) These updates did not include changes to the methodology for calculating avoided T&D.

We previously found merit to SDG&E/SoCal Gas's contention that a location bonus is appropriate for generators located in areas with local resource adequacy ("RA") requirements. As a result, we adopted a 10% location bonus for eligible CHP systems located in CAISO-identified location-constrained resource areas, which the Commission identifies as Local RA areas for purposes of establishing local RA procurement requirements. (D.09-12-042, pp. 38-39.)

For background, the Local RA program, approved in D.06-06-064, is intended to ensure that the utilities have acquired sufficient generation capacity to serve defined, transmission constrained local areas. Each year the Commission adopts Local RA requirements and identifies Local RA areas based on the CAISO's annual study of local capacity requirements.[25] The CAISO study identifies the specific substations included in each Local RA area – constrained areas that require the purchase of a specified amount of Local RA resources to avoid T&D system failures.

In D.09-12-042, we determined that eligible CHP interconnected within any of the identified Local RA areas should receive the location bonus. We required each utility to make these location bonus areas, including the specific substations included in each area, publicly available on its website. This information is required to be updated each year upon adoption by this Commission of the Local RA program requirements.[26] The location bonus is to be applied for the entirety of an AB 1613 CHP's contract term based on the Local RA areas identified in the year the contract is executed.

To the extent that parties believe that the 10% location bonus does not reflect avoided cost, or will push the MPR-based price above avoided cost, they are wrong. As an initial matter, it should be noted that all of the utilities agree that distributed generation, which includes AB 1613 CHPs, results in avoided T&D

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[25] The CAISO's 2008 Local Capacity Requirement (LCR) Study is available from the CAISO website, http://www.caiso.com/1c44/1c44bbc954950.html

[26] 2010 Resource Adequacy program requirements were adopted by this Commission in D.09-06-028.

investment. Nevertheless, the 10% location bonus will only be made available to new AB 1613 facilities constructed in Local RA areas. AB 1613 CHPs located in these Local RA areas will generate avoided costs to the utilities well above the 10% location bonus the utilities will pay them.

CCC Attachment A sets forth utility-specific avoided T&D costs by geographic "divisions" which average $5.60/MWh for PG&E's service area, $6.66/MWh for SCE's service area, and $13.03/MWh for SDG&E's service area, assuming a baseload profile, which is the profile of an AB 1613 generator. Based on these average avoided costs for T&D, a 10% location bonus paid to CHP facilities located in Local RA areas for avoided T&D investment is a conservative estimate of the actual T&D costs avoided in Local RA areas for several reasons.

First, the 10% location bonus is only paid on the amount of energy sold to the utility, and not on the amount of energy that the utility avoids producing due to the existence of the AB 1613 generator. Thus, the AB 1613 CHP will receive a payment for far less than the T&D costs it actually avoids. For example, when a utility achieves 10 MWh in energy efficiency savings, it gets credit for 10 MWh of avoided T&D costs, measured by the E3 Model and reflected in the CCC Attachment A. However, if an AB 1613 generator generates 10 MWh of energy, but only sells 1 MWh to the utility, while it avoids 10 MWh of generation, and thus, produces savings similar to 10 MWh of energy efficiency, the AB 1613 generator is only paid the 10% location bonus on the 1 MWh sold to the utility. Pursuant to AB 1613, generators must size output to load and may only sell their excess power to the utility. Thus, any payment to an AB 1613 generator for avoided T&D costs will be less than actual T&D costs avoided.

Second, the CCC Attachment A averages calculated from the data provided in the E3 model are based on avoided T&D investment in the *entire* utility service area. The 10% adder will only be paid to generators located in Local RA areas, which are the most constrained resource areas and will therefore have the highest avoided T&D costs. For example, CCC Attachment A shows that avoided T&D costs are as high as $9.17/MWh in PG&E's service area, $8.33 in SCE's service area, and $13.03 in

SDG&E's service area. In that regard, the 10% Location Bonus based upon "average" T&D costs is a conservative estimate of the cost actually avoided by the utility for T&D. Further, the avoided T&D costs reflected in CCC Attachment A are likely to increase as a result of utility filings for increases in transmission rates at FERC, and increases in distribution rates in Commission proceedings.

In adopting the 10% location bonus for AB 1613 generators located in local RA areas, the Commission recognizes that it must be consistent with federal law. The *FERC Clarification Order* explained that if the adder is based on an actual determination of expected costs of T&D upgrades it would constitute an avoided cost determination and be consistent with PURPA and Commission regulations:

> [I]f the CPUC bases the avoided cost "adder" or "bonus" on an actual determination of the expected costs of upgrades to the distribution or transmission system that the QFs will permit the purchasing utility to avoid, such an "adder" or "bonus" would constitute an actual avoided cost determination and would be consistent with PURPA and our regulations.

(*FERC Clarification Order*, *supra*, 133 FERC ¶ 61,059 at P 31.)

Further, the Commission has a great deal of discretion in determining this expected avoided cost. As the Ninth Circuit Court of Appeals recognized in *Independent Energy Producers*, the Commission has broad authority to implement Section 210 of PURPA, "states play the primary role in calculating avoided costs," and states have "a great deal of flexibility … in the manner in which avoided costs are estimated …." (*Independent Energy Producers Association*, *supra*, 36 F.3d 848, 856.) FERC recently affirmed and further clarified these principles in its *Clarification Order*. There, it emphasized the fact-specific nature of avoided cost determinations and its reluctance to "second guess" state determinations:

> As the Commission has previously explained, "states are allowed a wide degree of latitude in establishing an implementation plan for section 210 of PURPA, as long as such plans are consistent with our regulations. Similarly,

> with regard to review and enforcement of avoided cost determinations under such implementation plans, we have said that our role is generally limited to ensuring that the plans are consistent with section 210 of PURPA…." [*See American REF-FUEL Company of Hempstead*, 47 FERC ¶ 61,161, at 61,533 (1989); *Signal Shasta*, 41 FERC ¶ 61,120 at 61,295; *see also LG&E Westmoreland Hopewell*, 62 FERC ¶ 61,098, at 61,712 (1993).] In this regard, the determinations that a state commission makes to implement the rate provisions of section 210 of PURPA are by their nature fact-specific and include consideration of many factors, and we are reluctant to second guess the state commission's determinations; our regulations thus provide state commissions with guidelines on factors to be taken into account, "to the extent practicable," [18 C.F.R. § 292.304(e) (2010)] in determining a utility's avoided cost of acquiring the next unit of generation.

(*FERC Clarification Order* at P 24.)

The U.S. Supreme Court's holdings in *American Paper* further support the Commission's determination to adopt a uniform T&D avoided cost in the form of the 10% location bonus, instead of requiring the project-specific determination of prior years. In that case, the Supreme Court found that FERC appropriately adopted a uniform rule that every CHP was entitled to full avoided cost payments. Among other things, the Supreme Court referred to PURPA's legislative history stating that such rate determinations should not be subject to the same level of scrutiny typically applied to utility rate applications. The Supreme Court quoted that legislative history at length, including the directive to encourage CHPs:

> "[C]ogeneration is to be encouraged under this section and therefore the examination of the level of rates which should apply to the purchase by the utility of the cogenerator's or small power producer's power should not be burdened by the same examination as are utility rate applications, but rather in a less burdensome manner. The establishment of utility type regulation over them would act as a significant disincentive to firms interested in cogeneration and small power production."

(*American Paper, supra,* at p. 414, quoting from H. R. Conf. Rep. No. 95-1750, pp. 97-98 (1978).) The Supreme Court examined FERC's policy reasons for adopting the full avoided cost rule, instead of a generator-specific avoided cost. Among them, the Supreme Court recognized FERC's desire to provide development incentives, and that such development would serve the public interest:

> The Commission recognized that the full-avoided-cost rule would not directly provide any rate savings to electric utility consumers, but deemed it more important that the rule could "provide a significant incentive for a higher growth rate" of cogeneration and small power production, and that "these ratepayers and the nation as a whole will benefit from the decreased reliance on scarce fossil fuels, such as oil and gas, and the more efficient use of energy." [footnote omitted] 45 Fed. Reg. 12222 (1980).

(*Id.* at 415.) The Supreme Court properly noted that "[t]he Commission would have encountered considerable difficulty had it attempted to determine an appropriate rate less than full avoided cost." (*Id.* at p. 416.) Similarly here, the Commission's project-specific T&D adder has proven to be unworkable. To encourage CHP consistent with both federal and state law, the Commission adopts a uniform rule here to compensate AB 1613 CHPs located in Local RA areas for some portion of the T&D costs they allow the utility to avoid. Such a uniform rule is consistent with both FERC orders, and the Supreme Court's holdings in *American Paper.*

In summary, the 10% location bonus the Commission adopted in D.09-12-042 is consistent with FERC's regulations because it is based on an "actual determination" of the utilities expected T&D costs, as established in their general rate cases and incorporated into the E3 Model relied on here. Based on these costs, and as explained above, the 10% location bonus is a conservative under-estimate of the avoided T&D costs associated with AB 1613 generators situated in location constrained resource areas and will not result in AB 1613 generators receiving more than avoided costs for their energy sales to the utilities.

C. Limited Rehearing Is Granted To Modify D.10-12-055 To Cap the GHG Compliance Cost Pass-Through At Avoided Cost

1. Overview

A major point of discussion in this proceeding has related to GHG compliance costs and how these costs should be addressed in the AB 1613 contract. The Final Staff Proposal recommended that the utility Buyers should pay for GHG compliance costs for the excess electricity sold to the grid. This proposal was adopted in D.09-12-042. To cap the utilities' cost exposure, D.09-12-042 also provided that the Buyer's GHG cost obligation would only be up to the emissions associated with operating the CHP facility at the CEC's minimum efficiency levels ("CEC-based cap"). D.09-12-042 required the CHP facility to be responsible for any additional GHG compliance obligation deriving from suboptimal operation of the facility.[27]

The Joint Utilities PFM raised issues regarding administration of the GHG compliance pass-through. In response, an Amended Scoping Memo issued September 9, 2010 reopened the record to take comment on the following GHG compliance cost issues:

> (1) If Sellers require reimbursement for GHG allowance costs, at what intervals should invoices be submitted to the Buyers?
>
> (2) Is a test (market based or some other method) needed to ensure that the invoices submitted by the Seller leave the ratepayer no worse off than if the Buyer had managed these compliance costs? If so, how should the market test be structured?[28]

Parties' comments on the GHG questions posed in the Amended Scoping Memo reflected a wide range of views. Most parties focused on the questions asked.

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[27] D.09-12-042, pp. 48-49 (slip op.).

[28] Amended Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge dated September 9, 2010, at p. 5.

PG&E and SCE raised PURPA-based objections to the GHG compliance cost pass through. They referenced the *FERC Declaratory Order* in support of their claims. PG&E argued that the cost of GHG allowances should not be treated as a pass-through but as a component of the generator's production costs and included in the avoided cost payments due under the Seller's monthly invoice for delivered energy. (PG&E Comments, filed September 29, 2010 at pp. 4-5.) SCE contended that any resolution of issues related to GHG costs must be consistent with the global QF Settlement Agreement filed with the Commission on October 8, 2010.[29] (SCE Comments, filed September 29, 2010 at p. 3.) Fuel Cell and CCDC replied that the Commission should ignore these PG&E and SCE comments as they were outside the scope of the Amended Scoping Memo and therefore erroneous.

In response to comments received, D.10-12-055 determined that:

(1) Comments from PG&E and SCE regarding short run avoided cost calculations, as provided in the QF Settlement, are outside the scope of the Amended Scoping Memo and outside the record of this proceeding, and should therefore be disregarded. (D.10-12-055 at pp. 18-19);

(2) GHG compensation costs are "environmental externalities" like RECs and are therefore "external to avoided cost rates." (D.10-12-055 at p. 19); and

(3) The Seller may elect who will procure the GHG allowances for the excess power sold to the utility – either the Seller or the Buyer. (D.10-12-055 at p. 20). Thus, the Seller may elect to recover its costs up to the established CEC-based cap from the Buyer, or the Buyer will procure GHG allowances for the excess power purchases, up to the CEC-based cap.

[29] *Joint Motion for Approval of Qualifying Facility and Combined Heat and Power Program Settlement Agreement*, filed in the following dockets: Application 08-11-001, R.06-02-013, R.04-04-003, R.04-04-025, and R.99-11-022.

2. Joint Utilities' Applications for Rehearing

In their Applications for Rehearing of D.10-12-055, the Joint Utilities argue that the GHG compliance cost pass-through does not comply with avoided cost principles. Specifically, they claim that avoided cost is based on the *utilities'* costs avoided through the purchase of QF power, not the *generators'* costs, and that it is inconsistent with PURPA to provide for a direct pass through of a generator's production costs. (SCE's Rehrg. App., at p. 11; PG&E/SDG&E's Rehrg. App., at pp. 12-13.) They argue that D.10-12-055's reliance on the *FERC Clarification Order* is in error. PG&E/SDG&E characterize GHG compliance costs as production costs similar to other environmental compliance costs: "Like other costs incurred to comply with air quality, water quality, and land-use restrictions, GHG compliance costs are another cost of doing business." (PG&E/SDG&E's Rehrg App., at p. 13.) SCE similarly argues that, contrary to the position taken in D.10-12-055, the *FERC Clarification Order* supports the view that GHG compliance costs are not like renewable energy credits ("RECs"), but are production costs which cannot be passed through. SCE states:

> Contrary to the Decision … nothing in the Clarification Order supports a pass-through of the seller's production costs, regardless of the type of costs. The Clarification Order describes RECs as "separate commodities from the energy and capacity produced by QFs" and provides that "if a state chooses to create these separate commodities, they are not compensation for capacity and energy." [citation to Clarification Order at 16, n. 62.]
>
> Here, GHG compliance costs are not a "renewable energy credit" and they are not a separate commodity or product.

(SCE's Rehrg. App., at p. 12.)

3. Discussion

In determining how to best allocate GHG compliance costs, the Commission initially focused on the preliminary and evolving nature of the GHG compliance regulatory regime. As the Final Staff Proposal noted:

> It is difficult to know the value of GHG attributes and GHG compliance costs, if any, associated with eligible generation under this program until rules and regulations are established.

(Final Staff Proposal at p. 5.)

The Commission similarly recognized that California's GHG compliance regime was in its infancy. Because compliance will not begin until January 1, 2012, at the earliest,[30] the regime will not apply to all facilities at that time, and many critical elements of the regime have not yet been finalized, the Commission could not accurately quantify the costs the GHG compliance regime would impose. Consequently, the Commission determined it was appropriate to adopt the Final Staff Proposal's suggested cost pass-through. (See, e.g., D.09-12-042, at pp. 46-49.) The Commission was concerned that any other approach could over or under compensate AB 1613 CHPs for their GHG compliance costs, and that this would not meet the "ratepayer indifference" requirements of AB 1613.

Given the transition of the AB 1613 program to one implemented pursuant to PURPA, it is now apparent that any compensation for GHG compliance costs must be consistent with avoided cost principles.

There is merit to the Joint Utilities' rehearing arguments that the pass-through mechanism affirmed and elaborated upon in D.10-12-055 is not consistent with avoided cost principles. Among other things, the Joint Utilities are correct that GHG compliance costs are environmental compliance costs that should be included in the generator's costs of production. Consequently, we grant rehearing to the Joint Utilities on this issue. Parties previously had an opportunity to comment on this issue. Based on the record in this proceeding, we modify D.10-12-055 to adopt an earlier proposal made

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30 *See, e.g.,* the facts discussed in *Ass'n of Irritated Residents, et al. v. California Air Resources Board*, CGC 09-509526, Statement of Decision – Order Granting in Part Petition for Writ of Mandate, issued March 18, 2011 in Superior Court of California, County of San Francisco (reflecting possible delay in AB 32 implementation).

by SDG&E/SoCalGas that was considered, but rejected, in D.09-12-042. (See D.09-12-042 at p. 44 (slip op.).)

In comments responding to the Final Staff Proposal, SDG&E/SoCal Gas agreed that it was appropriate for the Buyer to pay for the GHG compliance costs associated with the excess energy sold to the utility. However, assuming adoption of the MPR-based pricing formula, SDG&E/SoCal Gas suggested that the cost pass-through be capped at the MPR heat rate so that the Seller would bear any GHG compliance costs for emissions associated with less efficient units. (SDG&E/SoCal Gas Opening Comments, filed August 24, 2009, at pp. 8-9.)

In order to comply with avoided cost principles, the costs paid by the utility to the AB 1613 CHP should not exceed the avoided GHG compliance costs of the proxy CCGT the Commission has relied on to establish the avoided costs for energy. The SDG&E/SoCal Gas proposal, by setting a cap at the MPR heat rate, properly caps the costs that may be recovered by an AB 1613 CHP to the proxy CCGT's avoided GHG compliance costs. Adopting the cap will ensure that the price paid to AB 1613 CHPs for GHG compliance will not exceed the utilities' avoided cost. Consequently, the Commission adopts the SDG&E/SoCal Gas proposal, and modifies D.10-12-055 (modifying D.09-12-042) accordingly.

Consistent with this determination, the Commission also modifies D.10-12-055 regarding the seller's right to choose to either procure GHG allowances itself and seek reimbursement from the utility, or have the utility procure GHG allowances for the excess electricity sold it. The Commission retains this election option. However, if the seller elects to have the utility procure GHG allowances for it, the utility's obligation to procure such allowances is capped at the number of allowances necessary to operate the proxy CCGT unit.

The Joint Utilities shall submit supplemental advice letters to amend the tariff sheets and contracts associated with the AB 1613 program consistent with these modifications.

Also consistent with this determination, we will eliminate the discussion in D.10-12-055 comparing GHG compliance costs to RECs (see D.10-12-055 at pp. 19-20), and otherwise modify D.10-12-055 (modifying D.09-12-042) to be consistent with the discussion above.

Traditionally, an avoided cost payment incorporates all elements of energy production into a single payment, and here we have two components that comprise the avoided cost payment to an AB 1613 CHP – the MPR-based energy price, and the GHG compliance cost pass-through capped at the avoided cost of the CCGT proxy unit. Among other things, this cost pass-through approach may be administratively burdensome for the parties. However, given the uncertainty surrounding implementation of California's GHG compliance regime, this two component avoided cost approach is appropriate at this time. It allows for the program to comply with PURPA using a proposal already in the record of this proceeding (by ensuring that actual cost payments not exceed the utility's avoided costs), and will allow AB 1613 CHP project development to move forward, resulting in the environmental benefits intended by AB 1613. While this payment scheme will apply to the life of contracts signed pursuant to the tariffs approved under this decision, the Commission may revisit this issue as to future AB 1613 CHP contracts when the GHG allowance markets have evolved and compliance costs are more easily determined or forecasted.

D. The Motion for Stay Is Denied

Ordering Paragraphs 9, 10, and 11 of D.10-12-055 direct each of the Joint Utilities to file supplemental advice letters to implement the standard and simplified AB 1613 contracts adopted in D.09-12-042 as modified by D.10-12-055 within forty-five days of the its December 17, 2010 mailing date.

As described above, the Joint Utilities filed their initial motion to stay D.10-12-055 on January 6, 2011, and this was dismissed as premature by Assigned Commissioner's Ruling on January 12, 2011.

The Joint Utilities then filed a joint motion to stay with their rehearing applications. In this stay motion, they requested a stay of D.10-12-055 until the latter of

resolution of the their Enforcement Petition at FERC or the effective date of a Commission decision on the Joint Utilities' respective applications for rehearing of D.10-12-055.

The Joint Utilities argue that a stay is appropriate because: (1) they are likely to prevail on the merits of their FERC Enforcement Petition, resulting in a changed AB 1613 pricing formula; (2) they will suffer serious and irreparable harm if the stay is not granted; (3) the balance of hardships supports a stay; and (4) there are other relevant factors in their favor, such as the certainty of pricing for AB 1613 generators. (Joint Utilities' Motion for Stay, at p. 3.)

The Joint Utilities filed their supplemental advice letters on January 31, 2011, in compliance with Ordering Paragraphs 9, 10, and 11 in D.10-12-055. Energy Division issued a notice of suspension on February 18, 2011 staying Energy Division action on those supplemental advice letters for up to 120 days for further staff review.

As an initial matter, this order disposing of the Joint Utilities' rehearing applications renders the first portion of the motion for stay moot. FERC's March 31, 2011, "Notice of Intent Not to Act," declining to initiate an enforcement action against the Commission, arguably renders the second portion of the motion for stay moot. Nevertheless, we address the merits of the motion for stay here and deny the motion.

First, given the modifications and clarifications to the AB 1613 program ordered herein, the Joint Utilities are not likely to prevail on the merits of a FERC Enforcement Petition.

Second, there is no irreparable harm to the Joint Utilities if the stay is not granted. Energy Division's suspension of the supplemental advice letters filed by the Joint Utilities under Ordering Paragraphs 9, 10, and 11 for up to 120 days ensures that the AB 1613 program will not be implemented until these modifications and clarifications are made. No AB 1613 contract may be executed until the tariffs are approved. (See CPUC General Order 96-B, General Rule 7.3.5 and Energy Industry Rule 5.3.) And even if contract execution were imminent, there is no issue of utility shareholders being at risk

for stranded costs because AB 1613 expressly provides that the costs of the contracts will be allocated to "benefiting customers." (Pub. Util. Code, § 2841 subd. (e).)

Third, the balance of hardships is strongly in favor of the public interest. AB 1613 was enacted to further environmental objectives, particularly the reduction of GHG emissions. President Obama and the U.S. Environmental Protection Agency ("EPA") have recognized the overwhelming scientific consensus, which now confirms that climate change is unequivocal and due primarily to human-induced GHG emissions, which come mainly from the burning of fossil fuels. (See, e.g., EPA Endangerment Finding, 74 Fed. Reg. 66496 at 66497 (December 2009).) AB 32,[31] and the Commission's D.10-04-055 and D.07-01-039, recognized the serious threats posed by GHG emissions and global warming, such as the exacerbation of air quality problems, the reduction in California water supplies, a rise in sea levels resulting in displacement of coastal businesses and residences, and increases in human health-related problems.

AB 1613 is an important part of the State's attempt to be part of the GHG solution, instead of part of the problem. Yet the Joint Utilities have taken action at every step to delay its implementation. A stay will further delay the implementation of the program, and the environmental benefits it was intended to produce.

In sum, there are no relevant factors in favor of a stay. The AB 1613 Program will not be implemented until we take action to ensure compliance with PURPA. A stay of D.10-12-055 to await final resolution of the Enforcement Petition in federal court (or to await resolution of a subsequently filed enforcement petition) will unnecessarily delay implementation of the AB 1613 program (including the Advice Letter submittal and review process) and harm CHP developers who are prepared to commit to construction under the program, resulting in further delay of the environmental benefits anticipated to result from this program, including GHG emission reductions. Consequently, the Joint Utilities' motion for stay is denied.

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[31] *See* fn 6, *supra.*

IV. CONCLUSION

Rehearing is granted on the limited issue of GHG compliance costs, and modifications to D.10-12-055, as described herein, shall be made: (1) modify our treatment of GHG compliance costs to be consistent with avoided cost principles; (2) clarify why the MPR-based energy price adopted by D.09-12-042 and affirmed in D.10-12-055 is consistent with avoided cost principles; (3) clarify why the 10% Location Bonus is consistent with avoided cost principles, and (4) conform D.09-12-042 with the modifications ordered by D.10-04-055 and D.10-12-055, as modified herein. Rehearing of D.10-12-055, as modified, is denied. We also deny the Joint Utilities' motion for stay as without merit.

THEREFORE, IT IS ORDERED that:

1. Rehearing of D.10-12-055 is granted for the limited purpose of addressing greenhouse gas compliance cost issues.

2. D.10-12-055 shall be modified as follows:

   a. The discussion in Section 1 "Summary" on pages 1 and 2 is replaced with the discussion at Section 1 "Summary" in the Conformed Version of D.10-12-055, attached hereto as Attachment A.

   b. The first full paragraph on page 3 starting "On January 20, 2010, …" is replaced with the first full paragraph starting "On January 20, 2010, …" on page 3 of the Conformed Version of D.10-12-055, attached hereto as Attachment A.

   c. The text of Section 7.1 "Discussion" on pages15 and 16 is replaced with the discussion at Section 7.1 "Discussion" in the Conformed Version of D.10-12-055, attached hereto as Attachment A.

   d. The title of Section 8 - "Remove Language Requiring IOUs to Purchase GHG Allowances" - on page 16 is modified to "GHG Compliance."

   e. A new heading "8.3.1 The Pricing Terms Established By The QF Settlement Do Not Apply To The AB 1613 Program" is added underneath the heading "8.3 Discussion" at page 18.

f. A new footnote is added to the end of the partial paragraph at the top of page 19 that reads:

"The QF Settlement decision, D.10-12-035, expressly declined to apply the QF Settlement price to AB 1613 CHPs:

The Proposed Settlement is comprehensive, but it does not resolve issues in numerous Commission proceedings implementing recent statutory requirements that pertain to QFs of 20 MW or less, such as new CHP systems under Assembly Bill 1613 (codified as Pub. Util. Code sections 2840-2845), except to acknowledge that the megawatt (MW) and GHG reductions will count toward the investor-owned utilities' MW and GHG reduction targets."

g. A new heading "8.3.2 Modification to Provision Regarding Procurement of GHG Allowances" is added above the first full paragraph on page 19 that begins "In addition, the FERC Clarification Order explains that compensation for …."

h. The first full paragraph on page 19 that begins "In addition, the FERC Clarification Order explains that compensation for …." is deleted.

i. The first sentence of the first full paragraph on page 20 that begins "However, the Joint Utilities make a reasonable request …." is modified to read:

"The Joint Utilities make a reasonable request in their Petition for Modification regarding which entity is best positioned to actually purchase the GHG allowances needed for an AB 1613 facility."

j. A new Section 8.3.3 "Modification to GHG Compliance Cost Pass-Through To Be Consistent With Avoided Cost Principles" is added at the end of Section 8.3 "Discussion" as set forth in the Conformed Version of D.10-12-055, attached hereto as Attachment A.

k. The title of Section 12 - "Changes Needed to Contracts in Light of Subsequent FERC Orders" - on page 27 is modified to

"Additional Changes and Clarifications Required in Light of Subsequent FERC Orders."

l. A new heading "12.1 Overview" is added underneath the heading "12. Changes Needed to Contracts in Light of Subsequent FERC Orders" at page 27.

m. A new heading "12.2 Amended Scoping Memo and Party Comments" is added underneath the second full paragraph starting "The significance of the FERC's Clarification Order …." at page 28.

n. The three paragraphs starting with the last paragraph on page 28 that reads "In consideration of the FERC Declaratory Order, …" and ending with the second full paragraph on page 29 that reads "Regarding the event that a QF loses its AB 1613 certification …" are replaced with the discussion in Section 12.2 of the Conformed Version of D.10-12-055, attached hereto as Attachment A.

o. A new section 12.3 "The Record Reflects That The MPR-Based Price Is An Avoided Cost" as set forth in the Conformed Version of D.10-12-055, attached hereto as Attachment A, is added after the second full paragraph on page 29 that reads "Regarding the event that a QF loses its AB 1613 certification …"

p. Section 12.1 "Discussion" at pages 29 to 32 is replaced with Section 12.4 "QF Status and Two Tier Pricing Structure" as set forth in the Conformed Version of D.10-12-055, attached hereto as Attachment A.

q. The following new sections are added to the end of Section 12.1 at page 32, as set forth in the Conformed Version of D.10-12-055, attached hereto as Attachment A: (1) Section 12.5 "A PURPA Contract May Include Sanctions For Non-Compliance With State Efficiency Requirements"; (2) Section 12.6 "The 10% Location Bonus Is Based On The Utilities' Avoided Costs"; (3) Section 12.6.1 "Record On The 10% Location Bonus"; and (4) Section 12.6.2 "Analysis Of The 10% Location Bonus."

r. The discussion in Section 13 "Comments on Proposed Decision" on pages 32 and 33 is replaced with the discussion at Section 13

"Comments on Proposed Decision" in the Conformed Version of D.10-12-055, attached hereto as Attachment A.

s. The Findings of Fact, Conclusions of Law, and Ordering Paragraphs are modified as set forth in the Conformed Version of D.10-12-055, attached hereto as Attachment A.

3. Rehearing of D.10-12-055, as modified herein, is denied.

4. The motion for stay of D.10-12-055 is denied.

5. The Joint Utilities shall submit supplemental advice letters to amend the tariff sheets and contracts associated with the AB 1613 program consistent with the holdings in this order within 30 calendar days of the effective date of this order.

6. For clarity and for the convenience of the parties and the general public, we hereby adopt the "Conformed" Versions of D.10-12-055 and D.09-12-042, attached hereto as Attachments A and B, respectively. These conformed versions of D.10-12-055 and D.09-12-042 incorporate all modifications ordered by subsequent decisions in this proceeding, including this order, with the exception of those modifications ordered by D.10-04-055 to D.09-12-042 which are superseded here. To the extent modifications ordered result in express conflicts among the decisions in this proceeding, the holdings of the last in time decision shall control with the exception that the discussions set forth in Sections 5, 9, 10, and 11 of D.10-12-055 are not intended to be modified and stand as written.

7. To the extent that the AB 1613 contracts require further amendments to be consistent with the Commission's decisions in this proceeding, Energy Division is authorized to address such amendments through the resolution and advice letter process.

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This order is effective today.

Dated April 14, 2011, at San Francisco, California.

MICHAEL R. PEEVEY
President
TIMOTHY ALAN SIMON
CATHERINE J.K. SANDOVAL
MARK FERRON
Commissioners

Commissioner Michel Peter Florio, being necessarily absent, did not participate.

EXHIBIT E

ReMAT Feed-in Tariff (Senate Bill 32)

Overview

PG&E's Electric-Renewable Market Adjusting Tariff (E-ReMAT) became effective on July 24, 2013. E-ReMAT was established by CPUC Decisions (D.) 12-05-035 and D.13-05-034 to implement Senate Bill (SB) 32, which increased the statewide procurement renewable target from 500 MW to 750 MW (applicable to both investor owned utilites and public owned utilities) and increased the eligible project size from 1.5 MW to 3 MW (AC). Since October 2, 2013, PG&E began accepting Program Participation Requests (PPRs). The first ReMAT Program Period commenced on November 1, 2013.

Tariff & PPA

E-ReMAT Tariff (PDF, 182 KB)

ReMAT PPA (DOC, 993 KB)

ReMAT Capacity Allocation, Product Types & Pricing Overview

Per (D.) 12-05-035, the initial program capacity that PG&E was allocated 218.8 MW of the 750 MW total statewide goal. This capacity allocation, reduced by capacity contracted for under the E-PWF and E-SRG tariffs, was made available under the E-ReMAT Tariff. The Effective Date was July 24, 2013.

There are three Product Types: As-Available Peaking, As-Available Non-Peaking, and Baseload. The Contract Price for all three Product Types will begin at $89.23/MWh on November 1, 2013, when the first ReMAT Program Period begins (Period 1). The Contract price for each Product Type will adjust independently, based on market subscription in that Product Type, in each subsequent bi-monthly Program Period. The ReMAT pricing mechanism is described in Section H of the E-ReMAT Tariff.

Program Period 4 (begins May 1, 2014)

5 MW available for each Product Type

Product Type	Price (per MWh)
As-Available Peaking	$65.23
As-Available Non-Peaking	$89.23
Baseload	$89.23

ReMAT Program Capacity (as of May 1, 2014)

	MW
PG&E's Allocation	218.800
Total existing E-SRG/E-PWF PPAs	90.201
Resulting Capacity	128.599
ReMAT Allocation for each Product Type	128.599/3 = 42.866
Total existing E-ReMAT PPAs	
• As-Available Peaking	11.770
• As-Available Non-Peaking	5.491
• Baseload	0.848
Available ReMAT Capacity per Product Type	
• As-Available Peaking	31.096
• As-Available Non-Peaking	37.375

	MW
• Baseload	42.018

Archived Program Capacity (PDF, 74 KB)

ReMAT Queue Information

Program Period 4 (PDF, 113 KB) 05-01-2014

PPAs Awarded

10-Day Reporting Requirement (XLS, 35 KB)

Eligibility

To learn about eligibility requirements, pricing, terms and the application process, please refer to PG&E's E-ReMAT Tariff and ReMAT Power Purchase Agreement (PPA), PG&E's ReMAT webinar presentations and Frequently Asked Questions.

How to Apply

To apply for the ReMAT program, you must register as an Applicant on PG&E's ReMAT online platform (powered by Accion Group) and submit a PPR. **The ReMAT program is officially launched. The link to the ReMAT Feed-in Tariff platform is now available at: https://pge.accionpower.com/ReMAT/home.asp.**

In the meantime, following are resources for interested applicants:

Frequently Asked Questions

PG&E will update ReMAT Frequently Asked Questions (FAQs) periodically as new questions about the program arise.

ReMAT FAQs (PDF, 145 KB) **Updated 12-12-2013**

PPR Form Worksheet (DOC, 680 KB)

Appendix E Guidelines (PDF, 173 KB)

ReMAT Webinars

PG&E hosted three webinars on ReMAT. The first webinar (Webinar 1) occurred on August 8, 2013, which provided a general overview of the ReMAT program.

Webinar 2 was held on August 16, 2013. The webinar covered the online platform that PG&E will use to accept PPRs.

Webinar 3 was held on September 26, 2013. The webinar recapped several ReMAT program details and covered frequently asked questions.

If the audio portions do not open in your browser, you will need to open Windows Media Player and copy the URL into your media file application.

Webinar 1: ReMAT Overview

ReMAT Webinar 1 presentation (PDF, 637 KB)

ReMAT Webinar 1 audio file (MP3, 11.5 MB)

ReMAT Webinar 1 attendee list (XLS, 36 KB)

ReMAT Webinar 1 Q&A (DOC, 47 KB) posted 08/18/2013

Webinar 2: Online Platform - Application and Program Period Process

ReMAT Webinar 2 presentation (PDF, 1.3 MB)

ReMAT Webinar 2 audio file (MP3, 9.5 MB)

ReMAT Webinar 2 attendee list (XLS, 31 KB)

ReMAT Webinar 2 Q&A (DOC, 41 KB) posted 09/03/2013

Webinar 3: Review of Program Details

- ReMAT Webinar 3 presentation (PDF, 491 KB)
- ReMAT Webinar 3 Attendee List (XLS, 34 KB)
- ReMAT Webinar 3 audio file (MP3, 8.2 MB) posted 10/15/2013
- ReMAT Webinar 3 Q&A (DOC, 39 KB) posted 11/05/2013

Interconnection Information

For information on the interconnection process, please visit PG&E's Wholesale Electric Generator Interconnection (EGI) website. Here you can find Fast Track and Independent/Cluster Study interconnection process overviews, FAQs, an interconnection map and a link to the EGI's online application form. Interested applicants may also send an email to EGI at wholesalegen@pge.com.

Contact Information

For information or questions about PG&E's Renewable Feed-in-Tariffs email to feed-intariffs@pge.com.

To receive regular updates on PG&E's Renewable FIT programs, you may also sign up for our email distribution list.

EXHIBIT F

Pacific Gas and Electric Company

ReMAT Queue Information: Program Period 4 (as of May 1, 2014)

Baseload:

- Capacity available in Product Type
  - Remaining in Program: 42.018 MW
  - Program Period 3: 5.000 MW
- Complete PPRs in Product Type
  - There are fewer than 5 different Applicants in this Product Type

As-Available Non-Peaking:

- Capacity available in Product Type
  - Remaining in Program: 37.375 MW
  - Program Period 3: 5.000 MW
- Complete PPRs in Product Type
  - There are fewer than 5 different Applicants in this Product Type

As-Available Peaking:

- Capacity available in Product Type
  - Remaining in Program: 31.096 MW
  - Program Period 1: 5.000 MW
- Complete PPRs in Product Type
  - Number of different Applicants: 18
  - Number of PPRs: 26
  - Sum total of capacity: 54.090 MW (173.95% of capacity remaining in Program)
  - Technologies: Solar PV
- Project list (in order of ReMAT Queue number)

Renewable Resource/Technology	Contract Capacity (kW)
Solar - Photovoltaic [PV]	1000
Solar - Photovoltaic [PV]	1330
Solar - Photovoltaic [PV]	3000
Solar - Photovoltaic [PV]	1500
Solar - Photovoltaic [PV]	1500
Solar - Photovoltaic [PV]	1000
Solar - Photovoltaic [PV]	1500
Solar - Photovoltaic [PV]	990
Solar - Photovoltaic [PV]	2000
Solar - Photovoltaic [PV]	1300
Solar - Photovoltaic [PV]	1000
Solar - Photovoltaic [PV]	3000
Solar - Photovoltaic [PV]	2000

Pacific Gas and Electric Company

Solar - Photovoltaic [PV]	1500
Solar - Photovoltaic [PV]	1500
Solar - Photovoltaic [PV]	2000
Solar - Photovoltaic [PV]	1700
Solar - Photovoltaic [PV]	3000
Solar - Photovoltaic [PV]	3000
Solar - Photovoltaic [PV]	1000
Solar - Photovoltaic [PV]	1500
Solar - Photovoltaic [PV]	1500
Solar - Photovoltaic [PV]	2000
Solar - Photovoltaic [PV]	1500
Solar - Photovoltaic [PV]	500
Solar - Photovoltaic [PV]	500
Total	**42840**

Notes:

- Additional PPRs may be deemed Complete at any time
- For any PPR with an existing contract, the expiration date (or the effective date of the exercise of a Seller termination right) of the existing contract must occur within 24 months of the expected execution date of a ReMAT PPA, in order for a PPR to be eligible to accept/reject the offered price
- A PPR must have an expected interconnection commercial operation date within 24 months of the expected execution date of a ReMAT PPA, in order for a PPR to be eligible to accept/not accept the offered price